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ENHANCED HEAVY OIL RECOVERY

PROBLEMS, INCENTIVES AND PRIORITIES

A STUDY PREPARED FOR
THE DEPARTMENT OF ENERGY, MINES AND RESOURCES
GOVERNMENT OF CANADA

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A. INTRODUCTION AND SUMMARY

1. Introduction

Enhanced oil recovery (EOR) processes represent an important potential means of increasing Canada's recoverable reserve. However, efforts to develop broadly applicable EOR techniques have met with mixed success. In many instances, this has been due to low levels of recovery. Particularly in applications where flushing efficiency is high, such as miscible flooding and thermal recovery processes, these low recovery efficiencies are indicative of poor sweep efficiency (conformance).

Notwithstanding the direct role of conformance as a determinant of recovery efficiency, much and probably most of the research and development (R and D) effort related to EOR over the past several decades has focused on increasing flushing efficiency. Only in the pursuit of techniques such as polymer flooding has some consistent concern for conformance improvement been evident over that period. Thus, even in those instances where an EOR process successfully reduced residual oil saturation, the beneficial impact was often diminished because that reduction was effective over only a restricted volume of the reservoir.

Within the past two to five years, there has been some increase in emphasis on improving conformance. For the most part, this effort, or at least that portion which has been published, has been directed towards both laboratory and

field pilot experiments (principally in California) involving divertants in the form of foams. Encouraging results have been obtained in a number of field trials, although much of this subject is still poorly understood and will require considerable clarification. In addition, the range of conditions over which divertants are applied will need to be broadened to include heavy oil, oil sands, and conventional oil operations in Canada.

There is also potential for improving conformance through other approaches such as infill drilling, the use of horizontal wells, prudent selection of completion intervals and well operating strategies. These alternatives, too, merit increased investigation.

An issue which is related to the choice of recovery process, as well as to the question of conformance involves the timing of an EOR process. Historically, the choice of a time during the life of a reservoir at which an EOR process was normally implemented may have been technically inappropriate in many cases, because it resulted in diminished ultimate recovery. However, that choice, while technically non-optimum, may have been economically justified. This question of timing and its ramifications for recovery efficiency, economics, and incentive-oriented development policies merits a thorough assessment.

2. Summary

This study reviews enhanced oil recovery technology from the viewpoint of potential for conformance improvement. Salient approaches which have been the subject of varying degrees of evaluation are described, and their impact or potential impact on conformance is discussed. Subsequently, more recent laboratory studies, as well as field experimental projects aimed specifically at improving conformance in heavy oil reservoirs, are described and evaluated.

Section B following, outlines the principal conclusions and recommendations of this study. These pertain largely to conformance improvement at both the field and laboratory levels. In addition, they address the question of timing of enhanced oil recovery. They also deal with related issues such as the determination of vertical transmissibility, and assessment of the practical significance of clay problems.

Section C after recognizing the common lineage of flushing efficiency and conformance, presents a separate discussion of basics for each of these parameters. Those factors which are important determinants of flushing efficiency and conformance are identified. Because of the emphasis in this study on conformance, its influencing or potentially influencing factors are discussed in greater detail. As a corollary, the basic requirements for improving conformance are presented.

Section D discusses the principal approaches which

have been employed or suggested as enhanced oil recovery techniques. These approaches have been subdivided into two categories--nonthermal, and thermal. The former includes a number of techniques which have undergone considerable investigation, such as flooding with polymers, surfactants, hydrocarbon miscible slugs, and caustic fluids. Also included are techniques of a more recent vintage, such as carbon dioxide miscible flooding.

Included in the section on thermal processes are descriptions of the two basic techniques--steam injection and in situ combustion. In addition, however, the concept of injecting steam together with additives which are intended to improve conformance is introduced.

Other enhanced recovery alternatives which have the potential to increase conformance are discussed. These include horizontal wells, in conjunction with steam injection, electrical conduction heating, and infill drilling.

Finally, a brief summary of enhanced oil recovery project activity in Canada and the United States is presented.

Section E deals with recent efforts to improve conformance and focuses specifically on the use of divertants. Laboratory investigations of divertants, and, particularly foams, are described. Limited investigations of cross-linking polymer gels are also outlined.

Four different field operations which include a total of six pilots are reviewed. All of these projects involved the use of foam or foam-based divertants as additives to steam in California heavy oil reservoirs.

Each operator's assessment of pilot performance, particularly as it relates to conformance improvement, is discussed. In addition, within the limitations of available data, an independant evaluation of the extent to which conformance improvement can be inferred from the pilot results is presented. In the case of the SUPRI pilot, this evaluation includes a special investigation involving the use of simplified three-component mathematical models to demonstrate the critical nature of certain gaps in our fundamental knowledge.

Section F enumerates the principal unresolved problems associated with conformance improvement. Subsequently, priorities are assigned to these problems, and programs or approaches aimed at their resolution are outlined.

Section G lists the study references.

B. CONCLUSIONS AND RECOMMENDATIONS

1. Conclusions

1. Pragmatically, recovery problems associated with conformance and flushing efficiency generally require separate consideration because of the distinct aspects associated with each. Fundamentally, however, they are unified at the pore level.

2. Improvement of conformance represents a very high priority objective for heavy oil, oil sands and conventional operations.

3. Industry effort aimed at improving conformance has increased significantly in recent years, principally in the United States. However, the importance of the problem justifies a very strong effort in Canada, particularly in heavy oil and oil sands, where low recovery levels appear to be due largely to poor conformance.

4. Divertants are a prospective means of increasing conformance. Field experiments in U.S. heavy oil operations in which foam and foam-gel divertants have been injected as an additive to steam have yielded encouraging results.

5. Results of field experiments involving divertants as steam additives in heavy oil operations have indicated substantial improvement in vertical conformance. Corresponding improvements to areal conformance are more difficult to discern.

6. The current state of knowledge regarding the fundamentals of divertant flow and behavior in a porous medium is beset by some serious gaps and apparent contradictions in key areas. Resolution of these problems is important and will require research at a correspondingly basic level. One key question which must be answered is whether, or under what conditions, foams block more effectively in high permeability than in low permeability zones.

7. There is evidence to suggest that industry's long-standing practice of waterflooding, after which enhanced oil recovery (EOR) may be implemented, may reduce recovery compared to the alternative of foregoing the waterflood and moving directly to EOR. If so, and if the difference between these alternatives is significant the associated technical, economic and policy implications are considerable.

8. Strategies associated with well configuration and operation can influence conformance. These include

well spacing (infill drilling), completion interval, and pattern type and orientation in vertical wells. Another technique with indicated potential in steam injection operations involves the use of horizontal wells.

9. Vertical transmissibility can play a key role in conformance and recovery. However, techniques for quantifying vertical transmissibility are insufficiently developed.

10. Just as the fundamentals of divertant flow require further clarification, similarly the flow fundamentals of emulsions and of polymers are in need of work which will answer some important questions.

11. Phenomena such as swelling of indigenous clays or hydrothermal synthesis of swelling clays have been observed both in the laboratory and in the field. However, the extent to which these phenomena are of practical significance in the field has yet to be established.

12. Potentially, techniques such as electrical conduction heating may permit heating of lower permeability regions which might otherwise receive little heat under a fluid displacement process. However, subsequent displacement of the electrically heated oil from the

low permeability region may constitute a serious problem because of fluid by-passing. Thus, the potential of techniques such as electrical conduction heating may not be realized if we cannot first solve the conformance problem for fluid displacement processes.

2. Recommendations

1. A strong and immediate effort should be mounted to understand and evaluate divertants. This effort should involve laboratory and field projects which are concurrent and not consecutive, as insight at both levels will be required simultaneously.

2. Laboratory work on divertants should be aimed at understanding the fundamental mechanisms underlying divertant behavior. Flow experiments should be kept simple, with the emphasis on control and interpretability. Two suggested approaches are core displacement tests, and micro-model runs.

   The program of fundamental research on divertants should address the following questions:

   a) How do the permeability and permeability distribution of a porous medium affect a foam's blocking effectiveness and stability? Most importantly, do foams block higher permeability media more effectively than they do lower permeability media? Does blocking effectiveness depend on whether a sand is consolidated or unconsolidated? Does the relationship between permeability and blocking effectiveness change depending upon the nature of the foam (i.e., foam quality or texture)? Does the presence of oil or brine affect this relationship?

b) Within a given porous medium, how do variations in each of the following parameters affect the blocking effectiveness and stability of a foam:

i) Foam quality
ii) Foam texture
iii) Presence of oil
iv) Presence of brine
v) Surfactant concentration
vi) Presence of a polymer gel additive (viscosifier)

c) How do the permeability and permeability distribution of a porous medium affect the blocking effectiveness and stability of cross-linking polymer gels? Does the presence of oil or brine influence the efficacy of the gels?

d) Having regard to the above questions, what are the corresponding behavioral characteristics of gel-encapsulated foam?

3. Field effort aimed at evaluating divertants should begin immediately in heavy oil, and oil sands pilot operations involving steam injection (both cyclic stimulation and flooding). The effort should then be extended to conventional oil operations which are under waterflood, and in which conformance problems have been identified.

Field experiments involving the injection of a divertant as an additive to steam should be implemented forthwith. In so doing, substantial care should be taken to first become familiar with the potential for using various interpretive techniques, such as radioactive tracers for injection well flow profiles, and chemical tracers to infer certain aspects of areal fluid distribution. It is strongly recommended that field experiments include control wells or patterns in addition to those which are undergoing tests with divertants. It is also recommended that before an operator undertakes divertant experiments in the field, the literature should not only be reviewed in depth, but contact should also be made with operators who are familiar with these chemicals and who can discuss field handling problems in detail.

4. Unresolved questions regarding the fundamentals of emulsion and of polymer flow should be resolved through a program of basic research. Two specific topics which should be examined are the capacity of oil-in-water emulsions to become trapped within and plug off pores, and the effectiveness of polymer in reducing mobility as a function of the permeability of the porous medium.

5. Reservoir/economic studies should be initiated to examine the question of timing of enhanced oil recovery

(EOR). Technical evidence suggests that ultimate recovery is reduced when EOR is implemented following completion of a waterflood, compared with the alternative of implementing the EOR process at an earlier stage (and possibly eliminating waterflooding altogether). If these studies confirm that, to a large extent, there is a significant technical advantage in early implementation of EOR, but a concomitant economic disadvantage, policies should be developed which would create the necessary incentives for maximizing recovery consistent with sound economics.

6. Field effort aimed at evaluating strategies for well configuration and operation should be encouraged. Techniques such as infill drilling should be evaluated as a potential step within a field's overall development plan for EOR.

7. Field effort aimed at evaluating the efficacy of horizontal wells in steam injection operations should be pursued to identify the specific circumstances under which it is the preferred choice of the well orientation.

8. A program aimed at quantifying vertical transmissibility should be implemented and should be coordinated along two distinct but complementary directions. The first

direction would combine geology, petrophysics, reservoir engineering, and statistics, to determine how much can be inferred about vertical permeability from core measurements and associated geological interpretation. The second direction would involve reservoir engineering techniques to infer vertical transmissibility from pressure transient tests, and/or history matching of temperature observation data in which there is a distinct vertical component of flow.

9. The conditions under which phenomena involving clay swelling or fines migration have an important practical bearing on field performance need to be identified. In this respect, two types of field experiment should be considered. In reservoirs which are undergoing steam injection, and in which a clay swelling problem is thought to exist, an additive such as ammonia should be injected to determine whether the problem can be mitigated. The second type of program would involve implementing post-test core hole programs in those thermal pilot operations where either clays or fines are suspected to have caused problems.

10. At this time, efforts related to recovery techniques such as electrical conduction heating should be confined to "pencil and paper" evaluations. As the efficient displacement of electrically heated oil is still likely

to be dependent upon developments in technology which will improve conformance (i.e., which will reduce bypassing at mobility ratios which are adverse, even with pre-heated oil), more aggressive development of electrical conduction heating should await the results of programs such as the development of divertants.

C. MAJOR RECOVERY PROBLEMS

1. General

This section outlines the salient factors in determining the efficiency with which oil is recovered from a reservoir. Overall recovery efficiency is characterized in terms of two component measures,--flushing efficiency and volumetric sweep efficiency (conformance). However, prior to discussing these two measures of efficiency, it may be useful to define or clarify some relevant terms.

2. Definition of Terms

The stages of recovery through which an oil reservoir may be developed have been traditionally referred to as primary, secondary and tertiary.

The primary recovery stage involves production of oil utilizing the reservoir's natural energy with no significant man-made modifications. This includes fluid drive by one or more of the following mechanisms: liquid expansion (at pressures above the bubble point), evolution of solution gas (pressures below the bubble point), natural water drive (either above or below the bubble point), and gas cap drive (below the bubble point).

Secondary recovery refers to processes which are implemented in an effort to increase oil recovery over and above the level which can be achieved by continuing under primary operations. The traditional methods of secondary

recovery have been waterflooding and gasflooding with the former being the most common approach by far. Thus a reference to secondary recovery in current literature usually contemplates waterflooding. An important common characteristic of these two recovery techniques is that they both involve immiscible fluid displacement. Accordingly, the displacing fluid (e.g., water) will expel only a portion of the oil in a group of pores with which it comes in contact.

Tertiary recovery processes normally involve a more exotic recovery mechanism, inasmuch as they are aimed at mobilizing and displacing oil which is left behind at the end of the secondary stage. However, some of these exotic recovery processes may be applicable at an earlier stage of depletion. For example, in the case of oil sands and certain heavy oils, recovery may involve steam injection from the outset of a well's life. In this case, a recovery process which is functionally tertiary, in the sense that it is exotic, is chronologically primary.

To avoid this kind of confusion, processes which are geared to increasing recovery over and above levels which could be achieved by conventional means such as waterflooding are referred to as enhanced oil recovery (EOR) processes.

The efficiency of any oil recovery process involving fluid displacement in a porous medium depends on, and indeed is the product of, two basic factors--flushing efficiency and

volumetric sweep efficiency (conformance). Flushing efficiency is a measure of the fraction of oil which the displacing fluid removes from any given pore, or group of pores, with which it comes in contact. Conformance is a measure of the fraction of total reservoir pore volume which is contacted by the displacing fluid (i.e., the fraction of pore volume which is swept). Sometimes, flushing efficiency and conformance are referred to respectively as microscopic and macroscopic displacement efficiencies.

These two measures will be discussed individually, as the distinction between them is substantial from a pragmatic point of view. However, this treatment should not be construed as an indication that the two factors are unrelated. In fact they are ultimately related at the pore level. Displacement on the scale of a pore (i.e., flushing efficiency) is determined by, among other things, pore and pore network geometry. However, this same geometry can influency overall access of displacing fluids to regions of reservoir on a macroscopic scale (i.e., conformance). Analogously, conformance, like flushing efficiency, can be viewed as being influenced by surface phenomena such as fluid-fluid interfacial tension and wettability. For example, certain fluid interfaces (e.g., foams or emulsions) at pore throats may retain their integrity despite the tendency of viscous forces to distort or rupture them. Thus, by virtue of pore scale phenomena, it may be possible to create stable interfaces which withstand certain levels of viscous force and thereby divert flow elsewhere (i.e., increase conformance).

Following is a discussion of the salient factors which affect flushing efficiency and conformance. It is noteworthy that there is a considerable degree of interdependence among some of these factors. For example, both wettability and temperature are identified as factors affecting flushing efficiency. However, wettability may itself be a function of temperature. Nevertheless, the two are discussed as distinctive factors because each is identifiable in a major way with flushing efficiency.

3. Flushing Efficiency

a) General

Effort over the last several decades to understand fluid displacement at the pore scale has centered mainly on interfacial phenomena. Thus most discussions of flushing efficiency normally deal with two principal interfacial mechanisms--capillarity and wettability. Another key determinant of flushing efficiency, and one which now appears to be receiving considerable attention, involves pore and pore network geometry.

Following is a brief discussion of the principal factors affecting flushing efficiency. Although no attempt is made to judge the relative importance of these factors, some emphasis is placed on the geometry aspect, if only because the pace of research in this area has increased and has provided some interesting results.

b) Influencing Factors

It is a matter of longstanding recognition that interfacial tension between fluids plays an important role in determining the efficiency with which one fluid displaces another. Thus, an immiscible displacement process such as waterflooding will leave a residual oil saturation in the porous medium. Indeed, the reduction or removal of interfacial tension with a consequent increase in flushing efficiency has been the precise aim of certain EOR techniques such as miscible displacement.

The role of wettability has also been recognized, if not completely understood, as an important determinant of flushing efficiency. Laboratory studies have demonstrated (Reference 1) that displacement of oil by water in a water-wet porous medium exhibits a higher flushing effeciency than displacement with those same fluids in an oil-wet medium.

A valuable discussion of displacement mechanisms at the pore and pore network levels has been presented by Wardlaw (Reference 2). Wardlaw identifies four mechanisms by which oil may be trapped during waterflooding. The first of these relates to unstable displacement conditions, whereas the remaining three can occur in a stable displacement situation.

The first mechanism, and one which has been well documented in studies of macroscopic displacement, involves viscous fingering at unfavorable mobility ratios. The propogation of these instabilities as dendritic channels or fingers which may subsequently coalesce further downstream can result in bypassing and trapping of oil. Because of its implications for macroscopic displacement, this trapping mechanism actually relates closely to conformance, which will be discussed later.

The second mechanism is termed capillary instability or snap-off. As water displaces oil in a water-wet pore, the water will surround much of the oil droplet as it is

being displaced from the pore, and may form a collar at the exit throat. As this collar of water grows within the exit throat, it can result in isolation (snap-off) of the oil within the pore body. Wettability and pore geometry play an important role in this mechanism.

In a heterogeneous medium, variations will occur in pore body and pore throat size and geometry, as well as in the connectedness of the pore network. Thus, if two branches of a pore network diverge from a common upstream point, and subsequently converge at some downstream point, the more rapid displacement of oil by water from one of the two branches may result in the isolation and by-passing of oil in the other branch. Whether bypassing will occur in larger or smaller pores depends upon the wettability of the system.

The fourth mechanism is referred to as surface trapping. In an oil-wet system undergoing displacement by water, roughness or irregularity of the pore surfaces may trap oil.

Thus, whether a certain wettability condition plays a favorable or unfavorable role in displacement efficiency will depend upon which trapping mechanisms are prevalent. A study which deals with two of these mechanisms, bypassing and snap-off, and which explores the effects of pore and pore network geometry in a water-wet system on residual oil

saturation, was recently published by Chatzis et al (Reference 3).

Another factor which may influence flushing efficiency is temperature. To the extent that temperature affects interfacial phenomena, it can be expected to play a role in determining flushing efficiency.

One parameter which is usually regarded as the target of flushing efficiency, but is in fact one of its determinants is oil saturation. Having regard to the above mentioned trapping mechanisms, Wardlaw (Reference 2) has noted that it is easier to prevent trapping of oil than it is to mobilize it after the trapping has occurred. The field scale implications of this result are that moving directly to enhanced oil recovery from the primary stage will result in greater oil recovery than if the enhanced recovery process follows waterflooding. If such an intervening stage of waterflooding is indeed prejudicial to ultimate economic recovery, then for those conventional oil reservoirs which either have not undergone or are not yet in an advanced stage of waterflooding, new industry practices and associated government policies which encourage implementation of EOR following primary depletion may be in order.

4. Conformance

a) General

As noted earlier, conformance, like flushing efficiency, is ultimately determined at the pore (i.e., microscopic) level. However, this discussion will deal principally with those factors which are normally regarded in terms of displacement at the macroscopic level. Broadly speaking, those factors can be classified in terms of the nature of the fluids in the reservoir, the characteristics of the porous medium, and the specifics of those design and operating factors which are under the control of the operator.

b) Influencing Factors

i) Fluid Displacement and Distribution

1.0 Mobility Ratio

As noted earlier under the discussion of flushing efficiency, displacement at an unfavorable mobility ratio can result in viscous fingering or channelling with consequent bypassing of oil. This phenomenon has been observed extensively in the field, has been confirmed on the laboratory scale and can be demonstrated on a theoretical basis. A significant aspect of this phenomenon is that it can result in poor conformance even in a reservoir which is macroscopically homogeneous.

The adverse effects of high (unfavorable) mobility ratio are particularly evident in the recovery of heavy oil

or bitumen by thermal methods such as steam injection under predominantly viscous forces. The poor conformance which is frequently experienced in these situations overshadows the high flushing efficiency of the process and results in overall low recovery efficiencies.

2.0 Gravity Override

In those instances where the displaced and displacing fluids differ substantially in density, gravity segregation of the fluids may occur. The extent to which this takes place is also a function of the vertical transmissibility and thickness of the reservoir.

In thermal recovery processes involving heavy oil or bitumen, the contrast in fluid densities promotes overriding of the displacing fluid. This may mean that, throughout most of the reservoir, such displacement as takes place is confined largely to the upper portion of the formation.

Broadly speaking, one approach to this problem is to develop techniques which will minimize this effect. A second approach, and one which will be discussed in Section D in relation to thermal processes, proposes to take advantage of the gravity override effect rather than attempting to minimize it (see Section D, Well Orientation).

3.0 Associated Water/Gas Zone

It is not uncommon in reservoirs generally, and in heavy oil/oil sands specifically, to encounter situations in which the oil member is either underlain or overlain, or both, by a zone of higher mobility (i.e. gas and/or water). If vertical transmissibility is sufficiently high, displacing fluids injected into the oil zone will tend to move rapidly upward or downward to the high mobility regions and thus bypass the oil. These zones of high mobility are commonly referred to as "thief" zones and often constitute a severe impediment to displacement processes. Again however, there are exceptions. For example, at their steam injection pilot in Peace River, Alberta, Shell are utilizing a high mobility zone which underlies the oil sands deposit as the conduit for heating the reservoir.

ii) Heterogeneity

It is a matter of common knowledge that hydrocarbon reservoirs are generally quite heterogeneous. This is particularly evident in the case of Canada's heavy oil reservoirs and oil sands deposits. Rapid and significant variations in lithology both laterally and vertically appear to be the rule rather than the exception. Indeed, it may well be that many conventional reservoirs are equally heterogeneous and that only the closely spaced drilling normally associated with heavy oil/oil sands development permits us to see the variability in this type of reservoir. Thus, equally close well spacing in some conventional oil reservoirs might reveal a comparable degree of variability in lithology.

It was noted earlier that, even in a fairly uniform reservoir, poor conformance may result because of adverse mobility or density ratios. However, reservoir heterogeneity will in most instances certainly aggravate the conformance problem.

Since a reservoir is sampled at only a small number of discreet points (i.e., wells) it follows that most techniques which attempt to quantify reservoir variability will incorporate a statistical approach. Although heterogeneity normally implies a variation in several reservoir properties (e.g., permeability, porosity) most of the attempts to define heterogeneity focus on permeability because of its direct relationship to flow and displacement.

Probably the simplest and most traditional approach to describing heterogeneity and to subdividing a reservoir into layers involves the capacity distribution curve. This is generated by first ranking permeabilities which have been measured throughout a productive interval in order of decreasing magnitude without regard to their physical position vertically in the reservoir. A cumulative probability distribution curve of capacity (i.e., permeability-thickness) is then generated. If the reservoir were perfectly homogeneous in permeability, a plot of cumulative capacity versus cumulative thickness would result in a straight line through the origin. Any deviation from homogeneity produces a concave-downward curve. Using this plot, the abscissa can be subdivided into an arbitrary number of intervals (equivalent to subdividing the reservoir into a number of layers) and an average permeability can be determined for each.

An obvious advantage of the foregoing technique is its simplicity. On the other hand, the ranking of permeability in order of magnitude without regard to physical location in the productive interval can be a serious shortcoming where vertical mechanisms such as cross-flow, gravity segregation or vertical heat transfer are important.

Subsequently, zonation methods were developed which would recognize the physical location of a layer within the reservoir. In a statistical technique proposed by Testerman (Reference 4), sub-units are aggregated to form

zones in such a way that within each zone there is a minimum variation of permeability and so that between zones the variation is a maximum. Following this first procedure at each well, a second calculation is carried out. This step involves a correlation of zones from well to well. The difference of the means of two zones in adjoining wells is compared with the difference that could be expected based on the variations measured within each zone. If the former is no greater than the latter, the zones are considered to correlate.

An approach described by Bennion and Griffiths (Reference 5) was developed to test for stratification. In this technique, the reservoir was first segmented horizontally into areas of common variance. Subsequently, it was subdivided vertically into strata, if strata were determined to be present. Finally, using this lateral and vertical segmentation, a statistically based procedure was used to predict the lateral extent and variations of the reservoir rock property undergoing analysis.

An approach suggested by Alpay (Reference 6) is aimed at developing reservoir zonation which is more closely tied to the stratigraphy of a given reservoir. The existence of thin beds and the difficulties in correlating them from well to well are acknowledged. A procedure is then proposed whereby an aggregate of adjacent thin intervals is defined. Each such aggregate is selected so as to include a larger

depositional interval during which environmental conditions are perceived to have been similar. This cluster of very thin beds with similar textural characteristics is termed a "band of genetic similarity" (BGS).

The strong influence of heterogeneity on conformance and therefore on recovery efficiency requires that it be considered carefully in any evaluation of a recovery process. In general, it is probably prudent to examine the feasibility of reservoir zonation and to consider both statistical and geological approaches.

Although most of the methods proposed for describing heterogeneity are not restricted in their application to any one parameter they are nevertheless often applied to the measurement of variability in horizontal permeability. However, even an accurate and complete quantification of the lateral and vertical variations in horizontal permeability would not guarantee an adequate characterization of the reservoir. Except in those cases where each layer is effectively isolated from the others and can therefore be considered as a separate reservoir, the question of vertical flow and therefore of effective vertical transmissibility must be resolved.

iii) Vertical Transmissibility

This factor plays a key role in such mechanisms as gravity override, diversion of flow into thief zones, cross-flow between layers and heat transfer. Irrespective of whether a particular recovery process is prejudiced or enhanced by one of these mechanisms, the potential importance of the vertical flow component must be considered.

However, the determination of an effective transmissibility to vertical flow constitutes a difficult problem. Because reservoir bedding is generally horizontal or near horizontal, a reservoir may contain numerous local barriers to vertical flow. Thus, vertical permeability measured in a core cut from clean sand matrix (i.e., with the barriers excluded) will not properly reflect the inhibiting influence of those barriers. On the other hand, if the core is totally intersected by even one such competent barrier, a zero value of vertical permeability will be measured.

This measurement problem is sufficiently important to warrant increased effort within industry. Two individual but complementary approaches could be pursued. One would involve the application of geological and statistical techniques aimed at estimating the extent and continuity of barriers to vertical flow. The second would rely on interpretation of bottom-hole pressure and/or temperature data in which vertical movement of fluid played an active part. For example, pressure transient tests could be conducted

between two sets of perforations which are at different elevations in the reservoir. The perforations could be at the same wellbore or at different wells. Correspondingly, monitoring and analyses of the upward migration of steam may provide an indication of vertical transmissibility for that recovery process.

iv) Clays

The propensity of certain clays, such as montmorillonite, to swell when contacted by fresh water has been abundantly documented in the literature. Accordingly, contacting of a pore matrix containing water-sensitive clays by fresh water from a waterflood or by condensate from a steam flood can result in decreased permeabilities and the consequent creation of a conformance problem.

Subsequent research has also revealed that even where montmorillonite is not initially present it may be formed by mineral reactions in the presence of aqueous fluids and heat. A recent study by Boon et al (Reference 7) describes the result of work aimed at identifying the most important mineral reactions which occur during thermal recovery operations. The major reactions were identified as the dissolution of dolomite, kaolonite, illite and quartz and the formation of montmorillonite, calcite, analcime and chlorite. It was also determined that while high flow rates promote dissolution, they can also impair permeability in fine grained or certain fines-containing formations such as Cold Lake sands through fines migration. These mechanisms then raise the possibility of conformance problems due either to chemical reactions (i.e., formation of montmorillonite) or physical processes (i.e., dispersion of fines at high flux rates) in formations where no such problems were originally present.

The extent to which hydrothermal synthesis of montmorillonite and fines dispersion leads to serious conformance problems in field situations has yet to be determined, although the occurrence of these reactions in the field has been documented (Reference 8). However, in view of the substantial laboratory evidence together with supporting field results, it would seem prudent to be cognizant of these phenomena and their potential for modifying reservoir permeability. Thus, for example, if a flow divertant is to be used as an additive to steam in an effort to redirect flow and increase conformance, and if the target formation is susceptible to clay synthesis problems, some treatment design modification such as the co-injection of ammonia to inhibit montmorillonite synthesis (Reference 9) may be required.

By the same token, as Boon et al (Reference 7) have pointed out, it may be advantageous to actually induce clay synthesis in zones which have already been swept, so that follow-up displacement is re-directed towards other regions of the reservoir.

v) Well Configuration and Orientation

Conformance is a function of flow geometry, which depends not only on the properties of the reservoir-fluid system, but also on the location and configuration of the flow boundaries (i.e., wells). That configuration in turn depends on the locations, both areally and vertically, of the productive intervals.

In idealized homogeneous systems undergoing displacement by, say, waterflooding, conformance is a function of mobility ratio and pattern configuration and is independent of spacing. In reality, however, where systems are areally and vertically heterogeneous, well spacing can have a direct bearing on recovery. This is particularly so in more complex processes such as steam injection where distance plays a role in heat loss, and in chemical flooding where phenomena such as adsorption and stability may be dependent upon distance and/or time. The question of well spacing, particularly as it pertains to infill drilling, is discussed further in Section D.

In reservoirs such as Cold Lake, where oriented vertical fracturing creates a directional permeability effect, the choice not only of pattern type but also of its orientation becomes an important consideration.

Selection of a suitable completion interval is widely accepted as an important determinant of performance

and needs little elaboration here. There are some circumstances where completion interval may have only a minor bearing on conformance, such as when there is good vertical communication in the near-wellbore vicinity between the completion interval and, say, an underlying water zone. Generally, however, choice of completion interval will have a bearing on flow geometry and therefore on conformance.

Implicit in most discussions of well configuration is the assumption that the wells are substantially vertical. However, recent successes in drilling horizontal wells (Reference 10) create the potential for new flow geometries and possibly increased conformance in certain types of reservoir. Additional discussion of the potential for horizontal wells in thermal recovery is presented in Section D.

vi) Well Operations

Most of the displacement processes, unless otherwise modified, are carried out at adverse mobility ratios. Consequently, if a finger of displacing fluid is created due to some non-uniformity in the system, and if transverse dampening effects are insufficient to cause its dispersal, then the finger will tend to propogate more rapidly than other points on the displacement front which are less advanced.

One of the consequences of this type of instability is seen most graphically in steam injection operations, though it is by no means restricted to that process. Frequently, in a pattern flood, the advance of the flood front from the injector to the surrounding producers will be highly non-uniform. For example, communication may be established between the injector and, say, one or two of the producers in a five-spot while the remaining producers remain isolated. This can and does occur at sub-fracturing pressures where no "oriented permeability" effects are apparent and may show no correlation with compass direction.

Certainly reservoir heterogeneity can trigger an instability at the displacement front which will result in this type of non-uniform pattern sweep. On the other hand, however, it is equally possible to account for the occurrence of this type of non-uniformity even in a perfectly homogeneous reservoir. Continuing with the example of an

inverted five-spot, if one of the wells in a homogeneous reservoir is produced at a higher rate than the others, even on a temporary basis, the displacement front will advance more rapidly in its direction. Because of the instability phenomenon in an unfavorable mobility ratio situation, a channel may ultimately develop between this producer and the injector at the expense of frontal advance towards the other three wells.

Of course, in an actual reservoir situation where both reservoir heterogeneity and non-uniformity in well production/injection operations are virtually assured, both factors may influence conformance.

c) Basic Requirements for Improving Conformance

At its most basic level, conformance improvement requires a favorable alteration of flow geometry within the reservoir. This applies at the microscopic scale where it can be viewed in terms of changes to pore and pore network conditions and at the macroscopic scale in terms of reservoir heterogeneity, well geometry and well operations.

In principle, a favorable alteration in flow geometry may be accomplished by one or more of the following steps:

1. The effective mobility ratio of the displacement process may be reduced to a more favorable level.

2. Reservoir permeability may be altered selectively in certain regions, for example by blocking of transmissible zones or by creating fractures.

3. The arrangement of sources and sinks (i.e., injectors and producers) may be changed. This could include their spacing, pattern type, pattern orientation, completion interval and well orientation (i.e., vertical or horizontal).

4. The relative strengths of individual sources and sinks could be altered. In more specific terms, well production and injection rates could be manipulated to minimize uneven frontal advance.

5. The oil in less transmissible zones could be mobilized selectively using techniques which do not rely on fluid displacement (e.g., electrical heating).

In Section D following, the salient recovery techniques which are either in current use or have received serious consideration are reviewed and their relationship to the conformance problem is examined. Subsequently, Section E describes recent efforts to improve conformance using flow divertants.

D. ENHANCED OIL RECOVERY TECHNOLOGY--SALIENT APPROACHES

1. General

This section offers a brief review of the various technical approaches to EOR. For purposes of discussion, these are subdivided into two broad categories, relating to non-thermal and thermal methods.

With the exception of polymer flooding, non-thermal EOR methods have not focused specifically on increasing conformance. Rather, they have been directed primarily towards improving flushing efficiency. However, because mobility ratios are adverse in most displacement situations, the conformance problem is generally pervasive. As noted earlier, thermal recovery methods achieve high flushing efficiencies in the invaded zone. However, again because of adverse mobility ratios, the zone of invasion tends to be quite restricted (i.e., conformance is poor). Thus, most EOR methods, both thermal and non-thermal, either create a conformance problem, or fail to remedy an existing one.

2. Survey of Technical Approaches

a) General

Historically, non-thermal recovery methods have been applied in light or medium gravity oil reservoirs, often following secondary recovery operations (most commonly waterflooding). Accordingly, the context in which these methods are generally considered relates to tertiary recovery, although this need not be so.

Thermal recovery methods have been applied largely in heavy oil reservoirs and oil sands deposits. Consequently, it is common for these methods to be employed as either the initial recovery mechanism, or as a follow up to primary depletion.

The following review of the initial directions taken in the development of EOR processes will be confined largely to a very brief description of the principal recovery processes. However, the discussion of a polymer flooding will be somewhat more extended inasmuch as this represents a recovery technique which is specifically aimed at conformance improvement. More recent efforts to improve conformance through the use of divertants such as foams and gels will be discussed at greater length in Section E.

b) Non-thermal Processes

i) Polymer

Water-soluble polymers can be added to water thereby creating a more viscous displacing fluid in a flooding operation. The initial intention of this approach was to increase the viscosity of the water/polymer mixture and thus shift the mobility ratio in a more favorable direction.

Two types of water-soluble polymer have been utilized. The first involves natural biopolymers such as xanthan gum. This is a polysaccharide produced by microbial fermentation. The second group consists of synthetic polymers referred to as partially hydrolized polyacrylamides. The molecules in both of these categories are characteristically very large with weights ranging from one to ten million.

Selection of an appropriate polymer in a specific application involves a number of considerations. An important economic consideration, and one which is generally pertinent to all chemical flooding methods involves the cost of the material. In this regard, the polyacrylamides have generally been less costly. Other factors which must be considered are adsorption of the polymer onto the surfaces of the porous medium, thermal degradation, biological degradation, mechanical shear degradation, instability due to high salt content or other chemicals (e.g., surfactants) or minerals (e.g., clay), entrapment within pores, and oxidation.

A clear discussion of these potentially deleterious factors is provided by van Poollen (Reference 11) and Mungan (Reference 12).

Characteristically, each of the two types of polymer displays greater susceptibility to some of these factors than to others. For example, polyacryamides are generally regarded as more susceptible to shear degradation. The polysaccharides, on the other hand, are more susceptible to microbial attack. However, it is somewhat risky to categorize each of the two types in terms of their respective strengths and weaknesses in a summary fashion. The rapidity with which new chemicals are being developed and introduced to the marketplace (see for example References 13 and 14) tends to quickly outdate, at least in part, a status summary of polymer characteristics in a report of this nature.

The potential advantage to mobility ratio which is realized by viscosifying water through the addition of polymer, is fairly obvious. However, investigators have reported (References 15 and 16) that retention of the polymer within the porous medium also reduces the effective permeability of the latter. At least one investigator (Reference 17) regards this permeability reduction effect as a potentially beneficial mechanism for oil recovery. The combined mobility reduction due to increase in apparent viscosity and decrease in permeability is often characterized by means of the resistance factor. This is simply the

ratio of mobility when water is flowing through a porous medium to mobility when polymer solution flows through that same medium. Thus large values of the resistance factor are indicative of effective mobility reduction by a polymer. Because polymer retention processes are not fully reversible, they may have a residual effect even after flushing with large volumes of water. This longer lasting reduction in permeability is referred to as residual resistance.

If an adverse flow profile due, for example, to permeability contrast between layers is to be remedied, a dramatic change in mobility ratio is required. This is demonstrated in a later section dealing with the use of simple flow models to explain observed behavior of foam divertants in modifying injection profiles. Specifically, the benefits of foam are difficult to explain unless they are regarded as, say, blocking more effectively in higher permeability media--a phenomenon which is supported by some laboratory studies.

This same kind of question must be posed with regard to polymers. For example, in a case history involving a successful polymer flood in Wyoming (Reference 18), the injection profile both before and after introduction of polymer was reported. The results are summarized in Table D-1. Prior to the use of polymer, the bottom perforations accounted for 95% of the flow into the injector with all of this volume

entering the top three feet. Some seven months after polymer injection, the bottom perforations were accepting 86% of the total flow. However, the distribution of flow over the ten foot interval of bottom perforations was much more uniform, with only a small fraction entering the top three feet. This radical change in profile cannot be accounted for on the basis of viscosity effects alone. Specifically, it would need to include a mechanism whereby mobility in the previously most permeable zone (i.e., the zone which initially accepted 95% of the flow in this example), undergoes a proportionately much greater reduction than does the less permeable zone. However, laboratory studies of the dependence of polymer resistance factor on permeability of the porous medium do not help in providing an explanation. For example, Vela et al (Reference 15) and Sorbie et al (Reference 17) report results which show that resistance factor varies inversely as permeability. This effect would tend to render a non-uniform flow profile even less uniform.

Some other mechanism or mechanisms will have to be identified to rationalize the observed behavior in the above example, or at least to provide some basis whereby polymer can be expected to render flow profiles more uniform. For example, if it can be shown that polymer will reduce mobility in the presence of water (i.e., in a watered out zone) to an appreciably greater extent than in the presence of oil (i.e., in a largely unswept zone), then it may be possible

to account for the observed field behavior cited in this discussion.

On the other hand, if no such mechanisms can be identified experimentally, and if field results fail to provide sustained encouragement, the directions of research in this area may need to be altered significantly. Accordingly, in terms of immediate objectives, it would appear that experimental clarification of certain fundamentals of polymer flow behavior are required. Specifically, the question of how polymer effectiveness in reducing mobility within a porous medium is influenced by differences within that medium (e.g., variations in lithologic properties and fluid distribution among layers) should be addressed forthwith.

ii) Surfactant and Surfactant/Polymer

Displacement of oil by means of surfactants evolved in recognition of the finding that it was possible to increase oil recovery by lowering interfacial tension between oil and the displacing medium (usually water). Wettability was found to be another important factor in oil recovery. Since surfactants were able to effect these types of change, a great deal of research was carried out subsequently on surfactant-based recovery processes. As such, the surfactant recovery mechanism was viewed principally in terms of reducing residual oil saturation (i.e., increasing flushing efficiency), so that the vast majority of surfactant-related research focused on interfacial tension and wettability.

Two different approaches to surfactant flooding were developed. The first involves the injection of a large volume of low concentration surfactant. In the second, a smaller volume of higher concentration surfactant is used. At lower concentrations, the surfactant is in equilibrium with micelles (aggregates of surfactant). At higher surfactant concentration, the micelles become a surfactant-stabilized dispersion of either water-in-oil, or oil-in-water (Reference 11).

The injection fluid will include three basic components--oil, surfactant, and water. In addition, a co-surfactant, usually alcohol, can be added. Also,

inorganic salts may be introduced as electrolytes in preparing the micellar solutions.

A key determinant of the economic success of a chemical flooding operation involves the degree to which the chemical is adsorbed on mineral surfaces within the reservoir. Adsorption plays a major role in surfactant retention and flood breakdown. One approach to mitigating this effect is to inject a sacrificial chemical, such as an inorganic salt, prior to introducing the surfactant. Another key factor which will be discussed shortly involves mobility ratio.

Other considerations which can limit the effectiveness of a surfactant flood are temperature and salinity. Holstein (Reference 19) summarized the limitations of surfactants (and polymers) with respect to these two variables to that point in time. A field test, which extends the salinity limitations on surfactant flooding has been described by Bragg et al (Reference 20).

Displacement stability considerations are, of course, paramount in determining the efficacy of a drive process. Adverse mobility ratios in a surfactant flood process will tend to confine the area contacted by the surfactant, and will also lead to more rapid deterioration of the flood. In an attempt to counteract this effect, polymers are often

injected as a follow-up fluid to provide a more favorable mobility ratio.

Thus, a surfactant polymer flood might include the following injection sequence (Reference 21):

1. low salinity pre-flush
2. surfactant and co-surfactant
3. water-soluble polymer solution (mobility buffer)
4. waterflood

Of course, with the introduction of polymer, factors such as degradation must be considered. Also, questions raised in the previous section which pertain to displacement capabilities of polymer in heterogeneous formations would need to be superimposed upon any assessment of a surfactant polymer recovery process. The requirement for a multiplicity of chemicals and the difficulties in designing a process which will surmount the limitations created by adsorption, degradation, and adverse mobility ratio render this a very complex and costly process.

iii) Hydrocarbon Miscible

Miscible displacement is a recovery process which is directed specifically towards increasing flushing efficiency (i.e., decreasing residual oil saturation). It recognizes that residual oil is a consequence of interfacial phenomena, and seeks to minimize (ideally, reduce to zero) the interfacial tension between the oil and the miscible fluid.

Historically, miscible displacement processes centered on the use of light hydrocarbons as the miscible fluid. Because of its high cost, the miscible fluid was usually injected as a slug, and might be followed by gas and/or water. Ideally, the flood would be designed so that the light hydrocarbon slug was miscible with both the oil and the follow-up gas phase. One variation of miscible flooding, known as the enriched gas process, involves injecting enriched gas (e.g., ethane through hexane) so that some of the intermediate components are transferred from the gas into the oil, thereby forming a zone of miscibility. Pressures associated with these processes must be sufficiently high to assure miscibility. A second variation, referred to as the high pressure lean gas process, can be applied to deeper reservoirs which contain undersaturated crude that are rich in intermediates. These intermediates are transferred to the gas from the oil and form an intervening miscible zone.

Water is often injected as a follow-up fluid, or one of the follow-up fluids for two reasons. Firstly, it is a less expensive displacing agent than gas. Secondly, it is introduced to mitigate the unfavorable mobility ratio which is a concomitant of the miscible processes, and which results in poor conformance and dispersion of the miscible flood.

Miscible flooding is perhaps the classic example in reservoir engineering of a recovery process which was designed around the objective of increasing flushing efficiency. Conformance improvement per se, was not a major goal except in those instances where reservoir geometry was naturally conducive to this (e.g., in a pronounced gravity drainage situation).

iv) Carbon Dioxide Miscible

It has been recognized for some time that carbon dioxide is relatively soluble in oil compared to, say, nitrogen or methane. The dissolved carbon dioxide swells the oil and renders it less viscous. Both of these represent positive factors in increasing oil recovery.

More recently, industry has become interested in the application of carbon dioxide as a miscible fluid. Depending upon the characteristics (e.g., gravity) and temperature of the oil, a pressure can be determined, above which carbon dioxide will be miscible with the oil. Once this occurs, as with the hydrocarbon miscible process, capillary forces are reduced to zero, and the oil may be more readily displaced towards the producer. If miscibility is not achieved, the carbon dioxide may engender a gas drive, or solution gas drive process.

To avoid the expense of continuous carbon dioxide injection, a number of variations have been proposed. Generally, these involve follow-up, or alternate injection of carbon dioxide with an immiscible fluid. In those reservoirs which are amenable to waterflooding, the supplementary fluid is usually water. In less permeable reservoirs, an immiscible (or less miscible) gas such as methane or residue gas may be utilized.

A number of problems or potential drawbacks associated with the carbon dioxide process have been identified (Reference 11, 137). These include the frequent lack of a readily available supply of carbon dioxide, the severity of corrosion due to formation of carbonic acid, and formation in the reservoir of resinous or asphaltic pricipitates as the carbon dioxide removes the lighter hydrocarbons from the reservoir oil. However, addressing the conformance problem specifically, there are some additional problem areas. For example, if there is some free carbon dioxide within the reservoir, an adverse mobility ratio situation will occur in that region. This will tend to promote early gas breakthrough, curtailment of production rate, and by-passing of oil. Where miscibility is attained, the affected oil will be rendered less viscous. As a consequence, it will have a tendency to finger through, and be dispersed within the more viscous oil ahead of it.

Most of the field projects involving carbon dioxide are probably not sufficiently advanced at this time to provide a strong perspective on the efficacy of this process.

v) Caustic (Emulsions)

The use of caustic solutions, most notably sodium hydroxide, to improve oil recovery has been the subject of patents, research, and field trials for over fifty years. Nevertheless, according to van Poollen (Reference 11, 104), there is no record of successful field applications of caustic flooding.

On the basis of laboratory studies, caustic has the potential to increase oil recovery through several mechanisms. One such mechanism involves the reduction in interfacial tension between the oil and water, thereby improving flushing efficiency. Also, as the acidic components within the oil react with caustic, the oil may be emulsified. Depending on the size of oil droplets in the emulsion relative to the pore dimensions, some of the droplets may become entrapped in pores during displacement, thereby causing a diversion of flow. This, in turn, has the potential to improve conformance (References 22 and 23). Another suggested mechanism which may influence recovery is the alteration of rock wettability by the caustic.

Thus, the direct action of caustic is towards alteration of surface phenomena, such as interfacial tension and wettability, thereby increasing flushing efficiency. However, the consequent formation of emulsions also has the potential, according to laboratory studies, to increase conformance, presumably through oil entrapment.

An attractive aspect of caustic flooding is the relatively low cost of the chemical. There are, however, some major problems. First, the presence in the reservoir of multivalent ions, such as calcium and magnesium, can interfere seriously with the process by increasing interfacial tension (References 22 and 23), or by precipitating insoluble hydroxides (Reference 11, 104). Second, clays with high ion exchange capacities can exchange sodium for hydrogen, and thereby deplete the caustic. A third potential problem is that temperatures in excess of 200°F may increase caustic consumption appreciably, and give rise to emulsion stability problems.

McAuliffe (Reference 24), carried out a series of laboratory experiments which recognized the emulsion forming properties of sodium hydroxide. However, instead of injecting the caustic to form the emulsion in situ, the oil-in-water emulsions were first prepared externally with sodium hydroxide and asphaltic crude oil. Droplet size distribution was found to be controllable by altering the concentration of caustic. For cores with permeabilities less than two darcies, permeability could be reduced by injecting emulsion. Furthermore, the reduction in high permeability cores was proportionately greater than in low permeability cores.

A field test involving the application of caustic as an additive to steam was attempted at Kern River, California (Reference 25). The authors concluded that

addition of caustic provided no benefit to oil production and may have been detrimental.

It is interesting that several authors have commented on the potential of caustic flooding to increase conformance by diverting flow due to entrapment of oil droplets in pores. However, there seems to be an absence of comment on the consequence of such a mechanism. Specifically, oil which is trapped is oil which will not be recovered. Accordingly, to the extent that large amounts of oil are entrapped, the value of flow diversion may be offset by the lost recovery.

In a subsequent section we will be discussing the application of foam as a flow divertant. Just as an emulsion can be viewed as a dispersion of a liquid within a liquid, similarly, a foam can be considered as a dispersion of a gas within a liquid. It may well be that both these materials share in common the capacity to divert flow because of the entrapment in pores of the dispersed phase. If so, then there is a legitimate basis for conducting studies which evaluate and compare the effectiveness of emulsions and foams in increasing conformance, and for assessing the economic implications of this comparison.

c) Thermal

i) General

Thermal recovery processes in general and steam injection processes in particular account for a large majority of the oil which is produced in the western hemisphere as a result of the application of enhanced recovery methods. Conceptually, thermal recovery refers to a spectrum of approaches which include techniques in their early developmental stage, such as electrical conduction heating, as well as those which have never advanced beyond the talking stage such as subsurface nuclear detonation. However, from a practical point of view, the two basic techniques which have received the most attention and have been most widely implemented are steam injection and in situ combustion. Of these two in turn, steam injection has been the preponderant choice to date.

There is a very large body of literature dealing with many aspects of the steam and combustion techniques at both the laboratory and field levels. The following very brief description of the essentials of these two basic processes is aimed principally at characterizing them with respect to flushing efficiency and conformance.

ii) Steam

There are two widely used steam injection techniques--cyclic stimulation and flooding.

In cyclic stimulation, each well acts as its own producer and injector. Thus, for example, steam might be injected into a well for one month. Subsequently, the well would be turned around to production and might have sufficient pressure to flow back for a matter of days or weeks, after which it would be placed on pump. Duration of the total production period might be three to six months. In some instances, depending upon the preference of the operator, the well might be shut in for a soak period of several days duration following steam injection and prior to placing the well on production.

In Canadian thermal pilot operations at Cold Lake, as well as in a number of commercial operations in Venezuela and California, cyclic stimulation has been an effective recovery technique.

In steam flooding, wells are assigned fixed roles as either injectors or producers. Concurrent with the steam displacement operation, the producers may undergo cyclic stimulation to generate early revenue, and provide some heat in the vicinity of the producing well bore. The major portion of California's heavy oil production relies on steam flooding.

Flushing efficiencies associated with steam injection processes are quite high. Specifically, in the region contacted by steam, flushing efficiencies are often in the range of 80 to 90 percent. On the other hand, conformance tends to be quite poor. The highly adverse mobility ratios associated with this kind of displacement will result in channelling and consequent low areal sweep efficiencies, even if the reservoir is macroscopically homogeneous. Also, the density difference between steam and the liquid components within the reservoir encourages gravity segregation and the resulting commonly observed phenomenon referred to as gravity override. As a consequence, vertical sweep efficiencies also tend to be low. Of course, reservoir heterogeneities may further diminish conformance.

Thus, steam injection processes can be characterized as highly effective in terms of flushing efficiency, but generally quite mediocre with respect to conformance.

iii) Combustion

This technique involves the injection of a gaseous oxidant such as air into a hydrocarbon bearing reservoir. Alternative oxidants are oxygen or enriched air. An ignition technique is used to initiate combustion which is maintained thereafter by a continuing supply of oxidant.

The simplest application of this technique is referred to as dry forward combustion. It is termed dry because the only injected material is the gaseous oxidant. Forward combustion implies that the flow of fluids and the advance of the combustion front are both from the injector towards the producer. In reverse combustion, fluid movement is from injector to producer. However, ignition is initiated at the producer and the combustion front moves in the "reverse" direction from producer to injector. The preponderance of combustion effort both in the laboratory and field involves forward combustion.

In a commonly applied variation of the forward combustion method, water is injected either concurrent with, or in slugs alternating with, the oxidant. The water serves as an inexpensive volumetric supplement to the oxidant, as well as a means of moderating temperatures within the reservoir. In addition, the water is intended to play a role in mitigating the channelling tendencies of the gaseous oxidant.

Although combustion differs significantly from steam, and is characterized by its own set of process and operating considerations, it too represents a displacement process with an adverse mobility and density ratio. Accordingly, although the combustion process is capable of high flushing efficiencies, conformance can constitute a serious problem.

iv) Steam Plus Additives

The generally low levels of overall recovery associated with thermal methods has prompted industry to develop modifications which will augment recovery. This effort has been aimed largely at developing additives to be injected in association with steam.

Some of the additives, such as carbon dioxide, intermediate hydrocarbons, and thin film spreading agents, do not seem to be focused specifically on improvement of conformance, although their advocates have not excluded this possibility.

Other additives, which are commonly referred to as divertants, are applied specifically with the intent of increasing conformance by reducing mobility in the previously flushed zones. Currently, the most common divertants are referred to as foams. They generally consist of a surfactant solution in conjunction with a non-condensing gas. By mixing the surfactant solution and gas, either external to or within the reservoir, a foam can be generated. As noted earlier in our discussion of emulsions, a foam can be considered as a dispersion of a gas within a liquid. As such, it bears a certain structural similarity to, say, an oil-in-water emulsion. The action of foam in reducing mobility and thereby promoting diversion of injected fluids to previously bypassed portions of a reservoir is discussed at greater length in Section E.

Another divertant which has been used in conjunction with foams in field applications involves cross-linking polymers or gels. These can be formulated with a time delay in gelation so that the fluids can be injected at a low viscosity, and will subsequently form a very high viscosity material at some distance from the wellbore. These too, are described further in the next section.

It should be noted that while recent applications of surfactants as steam additives have been directed towards increasing conformance, they may also play a concurrent role in increasing flushing efficiency. Laboratory core scale displacement experiments carried out by Isaacs et al (Reference 26) indicated that the addition of a petroleum sulfonate surfactant to water at 100°C resulted in significant reductions in residual bitumen saturations compared to water alone.

A type of steam additive described by Blair et al (Reference 27) involves a range of compounds referred to as Thin Film Spreading Agents (TFSA). These apparently act to either prevent emulsification, or break emulsions, and concurrently cause water wetting of rock surfaces. Ostensibly, very viscous water-in-oil emulsions which are thought to exist in the reservoir can be broken, with a consequent increase in overall mobility.

Two different TFSA compositions were tested as additives to steam in 15 wells undergoing cyclic stimula-

tion--eleven at Midway Sunset, and four at Kern Front, California. Of the eleven Midway Sunset wells, eight showed substantial increases in oil produced compared to anticipated production with steam only. Two of the four wells at Kern Front showed significant production improvements.

Notwithstanding the postulated mechanisms by which TFSA compounds are thought to operate, it would seem that significant additional clarification of their actions in the reservoir will be required. For example, does their capacity to alter rock wettability imply that their principal influence is on flushing efficiency rather than conformance? Viewed another way, if dispersions, such as foams or oil-in-water emulsions, have the capacity to affect conformance by blocking pores, how does this compare with the influence on conformance of TFSA compounds, which break rather than form emulsions?

v) Electrical

Conceptually, viscous oil within a reservoir can be heated by any one of several electrical methods, such as conduction, induction, and radio frequency (RF) heating. However, most of the developmental effort to date seems to have been directed towards electrical conduction heating. In terms of field effort, Petro Canada are operating a pilot in the Surmont area of the Athabasca deposit in which electrical conduction heating has been employed as the pre-heat phase for a subsequent steam drive.

Because of the inherent inefficiencies in generating electricity, it is particularly important that its application in reservoir heating be highly efficient. A potential drawback of the electrical conduction heating approach is that, unless corrective steps are taken, the paths along which heating may occur can give rise to conformance problems analogous to those experienced with fluid displacement at adverse mobility ratios. For example, if electrodes are located at wells in a reservoir so that the imposed electric field is essentially horizontal, and if that reservoir consists of layers of varying oil richness (i.e., varying water saturations), then the preponderance of current flow may be directed through the low resistivity, leaner members. Thus the zones of greatest interest will receive the least heat.

Some approaches to overcoming or mitigating the conformance problem associated with electrical heating have

been proposed. For example, Kern (Reference 28) proposes to position the electrodes so that one is above the formation in electrical contact with the upper layer of a reservoir, and the other is below the formation in electrical contact with the lower layer. When a potential difference is imposed, the electric field now has a vertical component. Specifically, the resistances offered by each of the layers are now in series rather than in parallel as was the case when the electric field was horizontal. Accordingly, it is anticipated that the richer layers will undergo the greatest amount of heating because of their high resistance along the path between electrodes.

Harvey et al (Reference 29) have proposed an electrical method to recover oil which is bypassed by a waterflood. In this approach, fresh water is injected and will normally enter the zones with the highest effective permeability to water (i.e., the zones which have been largely contacted during the flood). When a horizontal electric field is imposed subsequently, the current will tend to flow through the less resistive (i.e., previously bypassed) portions of the reservoir.

To the extent that further effort is directed towards the development of electrical conduction heating methods, the likeliest targest are oil sands deposits or heavy oil reservoirs. Because of the viscous oil contained in these formations, it may not be feasible to inject fresh

water, so that the abovementioned selective electric heating method may not be easily applicable. On the other hand, if the initial recovery process involves, say, steam injection, and if the resulting steam condensate and gases left in the reservoir at the end of this process offer a sufficiently high electrical resistance, then the application of electrical conduction heating as a follow-up technique to heat previously by-passed oil may be feasible.

The foregoing discussion has dealt strictly with the heating of selected regions within a reservoir. However, it is important that electrical methods be evaluated in conjunction with some type of displacement technique. Theoretically, it may be possible to generate sufficiently high temperatures electrically to vaporize liquids and sustain an autogenous drive without employing a fluid injection method. Failing this, however, some independent fluid displacement technique which follows the electrical heating phase will need to be considered. In this regard, certain questions must be resolved. For example, if electrical heating is successful in preferentially raising the temperature of a leaner low permeability oil zone, will a follow-up displacement process by constrained to move through that zone? That is, even a preferential viscosity reduction in the lower permeability layer may not be sufficient to preclude bypassing and channelling during the follow-up displacement.

vi) Well Orientation

As already noted, the adverse density ratio associated with the commonly used thermal recovery techniques can lead to override, and consequent poor conformance. A steam injection technique which is designed to capitalize on this density contrast, and to take advantage of proven horizontal well technology has been described by Butler et al (Reference 30).

Based on theoretical and scaled model studies, they propose a horizontal production well placed below the point at which steam is injected. Continuous steam injection at a controlled rate results in the formation and growth of a steam chamber above the horizontal production well. The heated oil at the chamber walls drains down to the production well with concomitant growth of the steam chamber upwards and laterally.

Of course, an adequate thickness of oil sands or heavy oil reservoir must be available to take advantage of the special features of this process. By the same token, there must also be a sufficient level of vertical transmissibility.

Essentially, this approach, though novel in itself, belongs to that family of techniques which have the potential to increase conformance by controlling well configuration or geometry. As such, it merits further evaluation as do

other geometry-related considerations, such as well spacing, completion interval and pattern configuration at vertical wells.

d) Other

i) Well Spacing (Infill Drilling)

Perhaps the simplest and most direct technique with the potential to improve conformance involves infill drilling (i.e., drilling up of an already existing development on closer spacing). Each recovery technique has its own peculiar set of associated costs; in the case of infill drilling, there is an obvious requirement for large capital expenditures. Nevertheless, the relative simplicity of the method and its potential for recovering oil in those regions which may be bypassed on larger spacing has prompted recent interest and debate.

Van Everdingen and Kriss (Reference 31) suggested that, aside from thermal recovery methods in viscous oil reservoirs, the only practical EOR technique is infill drilling combined with waterflooding. A rebuttal position was presented by Holm (Reference 32). He agreed that stepped up infill drilling was needed, but contended that large amounts of oil would still be bypassed unless suitable EOR methods are developed. Holm estimated that within the United States, infill drilling alone would add reserves of less than twenty-five percent as much oil as the U.S. has already produced. He estimated that this figure could be effectively doubled if both infill drilling and tertiary recovery methods were employed.

Gould and Munoz (Reference 33) determined that infill drilling could increase recovery in addition to accelerating production. They identified three parameters--viscosity ratio, infill water cut, and vertical heterogeneity--with respect to which infill recovery appears to show an optimum. As would be expected, infill drilling has a more pronounced benefit at highly adverse viscosity ratios. This is because the initial flood is characterized by poor pattern sweep with consequent large areas of bypassed oil which would be available to the infill wells.

The question of whether infill drilling is an appropriate EOR technique in a given situation depends not only on reservoir characteristics, but also on the planned timing of the infill activity. For example, in an oil sands deposit or heavy oil reservoir undergoing cyclic steam stimulation, infill drilling may increase the probability of undesirable channelling and siphoning off of steam, if one well is undergoing stimulation and its new infill neighbor happens to be on production. Of course, one could place groups of communicating wells on concurrent injection and production to alleviate this problem. However, this limits operating flexibility within the project. In this example, it may be possible to avoid channelling problems by drilling the infill wells at the end of the operating lives of the original wells. In that way, with the original wells suspended, and only the infill wells operating, new oil is recovered, but on a spacing which need not be closer than

that of the original development.

In summary, there seems to be general agreement that infill drilling has potential as an EOR technique. However, as with all such techniques, the effectiveness of infill drilling will be site specific, and will likely require evaluation on a field scale.

3. Status Summary of Enhanced Oil Recovery Project Activity

Historically, successful commercial applications of EOR methods in Canada began in the 1960's with the inception of hydrocarbon miscible flooding in conventional oil reservoirs. In terms of production, these projects have overshadowed the output of other EOR schemes.

However, in terms of current EOR effort within Canada, activity is centered largely on thermal recovery operations in the oil sands areas of Alberta and the heavy oil areas of Saskatchewan and Alberta. A recent survey of activities in this area (Reference 34) indicates that there are fourteen active thermal recovery projects in the heavy oil areas of Saskatchewan. Of these, three involve steam, and eleven are principally combustion.

In Alberta, there are some 61 active experimental projects. Of these 42 are in the oil sands--22 at Athabasca, 19 at Cold Lake, and one at Peace River. The remaining 19 projects are situated in various heavy oil areas throughout the province. Steam and combustion based operations constitute the preponderance and possibly the totality of EOR processes being employed in these areas.

Because of the paucity of published EOR production data in Canada, it is difficult to estimate the amount of incremental oil associated with any one process or region.

Results selected from a 1982 survey of EOR activity in the United States (Reference 35) are summarized in Table D-2. Only those projects which were reported as promising or successful by the operator, and for which total and incremental enhanced oil production figures were provided in the survey, were included in this summary. As indicated, steam injection processes are primarily responsible for the incremental enhanced oil production, with most of this, in turn, coming from steam flooding. The vast majority of steam-based processes in the United States are located in the heavy oil areas of California. Non-thermal EOR processes account for only 19% of the total incremental enhanced oil production. Correspondingly, in thermal recovery operations, 89% of the prospective projects are reported to be profitable. The corresponding figure for the non-thermal category is 46%.

Statistics for both Canada and the United States indicate that thermal recovery techniques are currently the dominant choice for enhanced oil recovery. Furthermore, it is not unreasonable to project that this dominance may continue well into the future.

However, it may be risky to draw the obverse conclusion, and assume that non-thermal EOR processes will be confined to a minor role, particularly in Canada. For example, if the relative lack of success of many non-thermal EOR projects is related to the waterfloods which

preceded them, (i.e., oil which was bypassed during waterflooding is still being bypassed during EOR), then successful development of conformance improvement techniques could result in a marked increase in oil production from non-thermal processes. Within Canada, where waterfloods generally have not reached the stage of maturity of their counterparts in the United States, there may still be opportunities to move to EOR at an earlier stage in the depletion process than would be the case if the waterflood were carried to completion. This too, has the potential to contribute to incremental production from non-thermal processes.

E. ENHANCED OIL RECOVERY TECHNOLOGY--RECENT EFFORTS TO IMPROVE CONFORMANCE

1. General

Section D preceding dealt with EOR technology on a fairly broad basis. As indicated, most of the effort to date has related to the improvement of flushing efficiency. Furthermore, much and perhaps most of the ongoing effort is still directed towards this objective. However, because of the priority which we believe should be assigned to the question of conformance, this section focuses on that EOR effort which is aimed exclusively, or principally, at improving reservoir conformance, particularly as it relates to heavy oils and oil sands. Even more specifically, it emphasizes the role of divertants, as activity in this area is substantial and is directed towards the conformance problem.

2. Current and Recent Research and Development

a) General

Laboratory effort in the area of divertant characteristics and flow properties will be reviewed to provide some background on our level of understanding of the behavior of these materials. Subsequently, some field piloting efforts involving the use of divertants in conjunction with steam injection will be described.

b) Laboratory Investigation of Divertants

i) General

Most of the work published to date in the area of divertants deals with foams. There has also been some recent laboratory research effort related to cross linking polymers or gels. Accordingly, the emphasis in this discussion will be on foams with some additional commentary on gels.

ii) Foams

Before describing some of the salient results of a number of laboratory investigations, a few important definitions and concepts are advanced.

1.0 Concepts and Definitions

Foam can be defined as any dispersed gas-liquid system in which the liquid is the continuous (and essentially incompressible) phase, and the gas is the discontinuous (and compressible) phase. Dispersion of gas in the liquid is usually achieved by adding a surfactant to the liquid phase.

Quality is that fraction of the total foam volume which is gas. Minssieux (Reference 36) suggests that in practice, foam quality varies from 50 to 99 percent.

Texture, a concept advance by Marsden and Khan (Reference 37), is related to average bubble size, and therefore to degree of dispersion of the gas within the

liquid. Thus, a finer texture implies smaller bubbles, and therefore, more gas-liquid interfaces per unit volume of foam. Viewed another way, for a given quality, it is possible to have a number of different foam textures.

Foaming agent concentration refers to the concentration in the liquid phase of the foam-inducing chemical (e.g., surfactant).

Half-life is defined as the time required for half of the initial liquid component of the foam to drain from the foam.

There are a number of modes of foam generation. Foam can be created either external to, or within a porous medium. In the former case, it may be generated by vigorous mixing or agitation of a gas with a liquid phase which contains a surfactant. In the latter, it can be formed by displacing a resident surfactant solution with a gas.

The mechanism by which foam flows through a porous medium has been described differently by different investigators. The apparent discrepancy between the following two descriptions of foam flow may simply reflect differences in experimental conditions and therefore need not represent a real contradiction. However, some resolution of the following two viewpoints will be required.

Holm (Reference 38) carried out experiments in a two foot long sandpack and observed that foam does not flow through the porous medium as a body, even when the foam is generated first and then introduced to the system. Instead, as the foam films break within a porous medium, the liquid and gas separate, subsequently reforming bubbles within the porous medium.

Owete et al (Reference 39), observed foam flow in a homogeneous micro-model, and provided the following description:

"Displacement of aqueous surfactant solution by air in a water wet homogeneous porous medium can be described as a modified channel flow; the liquid forms a network of interconnecting films around the sand grains and between pores; air is propogated in channels consisting of tubular bubbles flowing and extending through several pores; liquid and air are trapped in some pores; foam consisting of hexagonal (or pentagonal) bubbles, or other characteristic structures, was not generated, nor was 'breaking and re-forming' of bubbles observed."

The need for a reconciliation of these apparent differences with respect to breaking and re-forming of bubbles is reflected repeatedly in various areas of investigation involving foam flow. Some topics of concern involve the effect of absolute permeability on foam blocking effec-

tiveness, factors affecting foam stability, effects of quality and foaming agent concentration on foam blocking effectiveness, the influence of oil and brine, as well as some other considerations.

1.1 Effect of Absolute Permeability on Foam Mobility Reduction

As will be demonstrated in a later section involving interpretation of field pilot injection profiles, the question of a foam's ability to reduce mobility to different degrees in formations of differing permeability may be crucial in evaluating the potential for foam divertants.

Marsden and Khan (Reference 37), found that in consolidated sand the ratio of relative permeability to apparent viscosity for the foam decreases as absolute permeability to air decreases for a given foam quality. In consolidated sand, the relative permeability-apparent viscosity ratio decreases as air permeability decreases for a given foam quality, but to a much lesser extent than for the unconsolidated sand. However, if one compares their results in consolidated media on the one hand, with those from unconsolidated media on the other, the relative permeability-apparent viscosity ratio decreases as air permeability increases for a given foam quality.

Bernard and Holm (Reference 40), found that foam reduces the gas permeability of high permeability sand to a greater degree than that of a low permeability sand. They concluded that foam should cause, to some degree, a selective plugging of high permeability sands.

Albrecht and Marsden (Reference 41), concluded on the basis of limited tests that gas flow blocking is more pronounced in unconsolidated porous media than in consolidated ones.

Sharma et al (Reference 42), found a linear relationship between foam displacement efficiency and permeability of the porous medium. They concluded that foams are more effective in loose sandstones than in tight sandstones.

Patton et al (Reference 43), concluded that foam viscosities measured in a capillary tube viscometer are much higher than those measured by applying the Darcy equation to flow through a porous medium. They also noted that when studying foam in capillaries, the ratio of capillary diameter to bubble size must be considered, and should probably equal 30, if the foam is to be treated as a continuum.

1.2 Foam Stability

Factors affecting foam stability represent another key area of concern.

Within the context of this study, where we are considering foams primarily (though not exclusively) as additives to steam, the question of temperature is critical. Wilson et al (Reference 44), observed that foam effectiveness is a function of temperature for a given foam. Within industry, continuing efforts are being made to develop foams which will remain stable at progressively higher temperatures.

According to Bernard and Holm (Reference 40), foam stability in a porous medium appears to be a function of specific permeability. The higher the permeability the lower the foam stability.

The relationship between foam properties as measured outside a porous medium, to foam stability within that medium represents another area which may require further resolution. For example, Doscher and Hammershaimb (Reference 45), conclude that foam stability exterior to a porous medium appears to be an important indicator of the foam's potential for reducing mobility within a porous medium. However, Dilgren et al (Reference 46), state that no reliable correlation was found between stability of a given foam within a porous medium, and stability of that

same foam outside the porous medium. This is because porous media tend to stabilize foams. Sharma et al (Reference 42), observed that surface properties of foaming solutions and microscopic characteristics of foams correlated strongly with the flow behavior of a foam in a porous medium.

A further observation related to foam stability by Patton et al (Reference 43), indicated that foams generated by dispersing a gas in a liquid which contains a water-soluble polymer, are more stable, and have higher viscosities than similar foams containing no viscosifier.

1.3 Foam Quality

The influence of foam quality on its mobility is another area that requires resolution. For example, Holm (Reference 38) concluded that mobility increases with an increase in foam quality. However, Marsden and Khan (Reference 37) concluded that mobility decreases (i.e., apparent viscosity increases) with an increase in foam quality. Minssieux (Reference 36), carried out rheological determinations with a viscometer, and observed that apparent viscosity increases with increasing foam quality. However, measurements in a porous medium indicated that apparent viscosity decreases with increasing foam quality. Correspondingly, within a porous medium he observed that recovery efficiency increases as foam quality decreases. Patton et al (Reference 43), found that higher quality foams are more viscous than lower quality foams based on rheological measurements in small capillaries. Albrecht and Marsden (Reference 41), also observed that wetter foams blocked a porous medium more easily.

1.4 Foaming Agent Concentration

There appears to be more agreement on the question of how foaming agent concentration influences mobility reduction. For example, both Bernard and Holm (Reference 40), and Albrecht and Marsden (Reference 41), observed a greater foam blocking effectiveness as the concentration of the foaming agent within the liquid phase is increased.

1.5 Presence of Oil or Brine

Within the reservoir, foams will come in contact with indigenous fluids. Accordingly, their influence on foam effectiveness is a matter of concern. Several investigators have examined foam behavior in the presence of oil. Bernard and Holm (Reference 40), observed that in a porous medium, oil generally decreases the effectiveness of foam as a mobility reducer. Specifically, it increases the rate of decay of the foam. Holm (Reference 38), observed that oil reduces the capability of a foam to trap gas. Eson and O'Nesky (Reference 47), concluded that addition of oil to a surfactant improved foam volume and half-life in many cases. In their studies of SUNTECH IV surfactant, Al-Khafaji et al (Reference 48), observed that partitioning of the surfactant in the oil phase increases to as much as 30% of the initial concentration after one day. After that, there is no further significant partitioning. Patton et al (Reference 43), observed that oil had only a slight effect on the foaming properties of the more promising surfactants which they were examining.

Bernard and Holm (Reference 40), observed that brine has little effect on foam effectiveness. Similarly, Kanda and Schechter (Reference 49), noted that the presence of salt in the surfactant solution did not alter the results significantly. Dilgren et al (Reference 46), observed that increasing the sodium chloride concentration to six or seven weight percent at 100°C caused two foaming agents (Siponate

and Witco 4498-43v) to salt out. Al-Khafaji (Reference 50), found that concentrations of sodium chloride at or in excess of two weight percent caused SUNTECH IV to precipitate and degrade. Eson and O'Nesky (Reference 47), observed that addition of 400 ppm of calcium had only a small effect on foam volume but adversely affected half-life. Al-Khafaji (Reference 50), observe[illegible]at calcium chloride in concentrations of 0.5 weight percent or greater, causes degradation of SUNTECH IV surfactant.

1.6 Shear Rate

The effect of shear rate on foam properties was investigated by Minssieux (Reference 36). He found that apparent foam viscosity decreases as shear rate increases. Although this is a rheological determination, it likely has some bearing on the question of foam blocking effectiveness as a function of formation permeability.

1.7 Experimental Factors

The difficulties in unifying many of the foregoing results are no doubt abetted by the many variations in experimental conditions from one investigator to another. These include surfactant type, foam quality and texture, pressure, temperature, and nature and pore characteristics of the porous medium. Additional potential confounding factors relate to artifacts of the experimental procedure. For example, Marsden and Khan (Reference 37), concluded that the method of foam preparation influences the texture of the foam. Thus the results of experiments in which foams are prepared by agitation or violent mixing should not be compared to those obtained when foam is generated by flowing both phases through a porous medium. They also suggested that foams which break or drain readily should not be compared with longer-lived foams unless both are being constantly regenerated.

iii) Gels

Gelled polymers, used either alone or in conjunction with foams, offer another potential means of diverting flow and increasing conformance. The salient characteristic of these materials is that they are injected into the porous medium as relatively low viscosity liquids, and subsequently gel within the reservoir to form a higher viscosity divertant. The in situ gel formation process involves a multivalent metal ion, a reducing agent, and a polymer.

Gelation times as a function of several variables have been studied by Terry et al (Reference 51). They found that for a constant concentration of metal ion-reducing agent system, the reciprocal of gelation time varies in an inverse linear manner with the reciprocal of the initial polymer concentration. Thus, longer gelation times are required when polymer concentration is decreased, for a given metal ion concentration. Also, for a given polymer concentration, a decrease in metal ion concentration results in longer gelation time. At the temperature of 25°C used in this study, gelation times could be varied from a few minutes to nearly a month with the systems employed in the experiments.

An investigation, which included experiments with gels at elevated temperatures as well as flow tests through porous media, was carried out by Navratil et al (Reference 52). Three different gels were tested. These materials had

initial viscosities in the range of 2 to 30 cp, with a rapid viscosity increase at gelation time. Table E-1 summarizes the gelation times and corresponding temperatures for the three gels. All three types were reported to have good resistance to heat. However, only the HT gels can be injected at steam temperatures without premature gelation.

Two types of experiments were carried out, involving flow through porous media. The first involved injection of low pressure (30 psi) steam into a slim steel tube containing tar sand. After displacing the bitumen down to residual oil saturation (approximately 20%), permeability was measured. Subsequently, a 15% solution of HT blocking agent was injected, and permeability was again measured. The second set of experiments involved an unscaled test of the steam diverting ability of the Geoseal TM gel. Steam was injected into a steel cylinder containing tar sand, except for a thin layer of very high permeability sand at the level of a steam injection port. Following a period of steam injection, a 15% Geoseal TM gel was injected to breakthrough and was followed by a water flush. After gelation, steam was again injected.

In the flow experiments, permeability to steam was reduced to 13 md from 3000 md by the HT gel at 200°C. Maintenance of this temperature for a subsequent sixteen hour period did not alter the measured permeability.

In the flow diversion experiment, some four pore volumes of steam were injected without recovering noticeable amounts of oil. Pressure drop across the system was approximately 1 psi. The gel was then introduced, after which steam injection was resumed. Pressure drop across the system was some 52 psi, and 11.6 percent of the oil in place was recovered.

In a subsequent section, field piloting experiments reported by Eson et al (References 53, 54, 55, 47) describe the results of tests involving the injection of foams, and gel-encapsulated foams.

c) Field Pilots Involving Divertants

i) General

In recent years, experimentation with divertants, principally foams, on a field basis has been carried out within industry at an accelerating pace. This section reviews, in varying degrees of detail, the results of six of those pilot operations, all located in the heavy oil areas of California. Also, in the case of two of the projects, supporting laboratory experiments which form part of the overall effort are discussed.

Within the limits of the available data, these reviews are supplemented in several instances by additional commentary on selected aspects of the effort. This commentary is most extensive in the case of the SUPRI project, as it includes an additional separate section (E.3) which addresses certain aspects of divertant flow behavior in greater depth.

ii) SUPRI Project (Reference 56)

1.0 Background

Under the guidance of Stanford University Petroleum Research Institute (SUPRI), a field pilot is being operated on the McManus lease of the Kern River field near Bakersfield, California.

The experiments, which are being carried out under a contract with the U.S. Department of Energy (DOE), are aimed at increasing production through a corresponding improvement in conformance, using a foaming surfactant (SUNTECH IV) together with nitrogen, as a divertant for injected steam. Specifically, the principal objectives of this work are to demonstrate the effectiveness of SUNTECH IV in reducing gravity override and channelling as well as increasing oil recovery over and above that obtainable by conventional steam drive in the same reservoir. Other objectives include the development of handling, storing and injection procedures for SUNTECH IV and verification of its longevity under steam drive conditions. Also various operational options such as varying the surfactant slug size are to be evaluated.

In addition, this project offers an opportunity to evaluate various formation evaluation and reservoir engineering techniques such as the use of gamma ray and spectral logs to identify steam zones, tracer surveys to define injection profiles, carbon-oxygen logs to determine

the vertical distribution of hydrocarbon saturation, and pressure fall-off tests to establish steam zone volume.

2.0 Laboratory Screening Tests

Prior to the field piloting effort, a series of laboratory tests was carried out to identify a suitable divertant for application in the field.

The first stage in this screening process involved boiling surfactant solutions at atmospheric conditions while varying their concentrations and the amounts of salts and crude oil present. Nitrogen was bubbled through the solutions to minimize the possibility of reactions with oxygen from the air. The resulting foaming ability of the surfactants (i.e., the height of the foam columns) and the durability of those foams (i.e., column height after one week) were measured. Only one-third of the surfactants tested were still foaming at the end of one week.

The surfactants with the most favorable foaming characteristics were then flowed at typical steam injection temperatures (350 to 400^{o}F) and pressures through a one-dimensional sand pack. The pack was first saturated with surfactant solution and subjected to the appropriate temperature and pressure conditions, after which nitrogen was injected. The resulting reduction in mobility and delay in breakthrough provided the criteria for assessing the effectiveness of the surfactant as a diverting agent. The most successful surfactants were employed in a repeat procedure but with the sand pack containing oil and irreducible water.

Surfactants were also held under nitrogen cushion for several weeks at 500 psi and 450 degrees F to test their longevity. To approximate field conditions, sand, crude oil and inorganic salts were added. Measurements were taken of surface tension, surfactant concentration, pH and conductivity.

Mobility reduction tests were also carried out in a two-dimensional vertical plexiglass sand pack. The base case involved displacement of water by nitrogen. When the pack was saturated with surfactant solution instead of water, liquid recoveries increased sharply and breakthroughs were delayed.

These procedures demonstrated that, in a laboratory setting, oil recovery could be increased by the use of foam divertants, and gravity override of injected gases could be sharply reduced. Also, based on these procedures, SUNTECH IV was identified as a suitable surfactant for field experiments involving divertants.

3.0 Field Pilot Experiments

3.1 Background

In September, 1980, under a contract with the U.S. Department of Energy (DOE), SUPRI undertook a field pilot experiment involving the use of SUNTECH IV in a steam drive. The pilot is located on the McManus lease of the Kern River field, near Bakersfield, California. Lease operator is Petro-Lewis Corporation. Thermal recovery operations began in the field in 1961 with cyclic steam stimulation, which was followed by steam flooding in 1962. The McManus lease, which is under steam flood, is developed on a 2.25 acre five-spot pattern.

The pilot experiment involves two nearby but non-adjacent patterns (see Figure E-1). Each of the two patterns is an inverted five-spot, with the test pattern centered around well number 208 and the control pattern around well number 214.

SUPRI has enumerated some nine specific goals of the field pilot experiment. Broadly speaking, however, the objectives of the pilot are to evaluate the efficacy of SUNTECH IV in increasing conformance, develop practical handling, storing, and injection procedures, verify the longevity of the diverti ant under steam drive conditions, and assess the commercial prospectiveness of this approach.

Some of the formation evaluation and reservoir engineering techniques which are being or will be utilized during the course of the pilot operation, are as follows: cased hole logging, injectivity profiling, pressure fall-off tests, production and casing vent gas measurement, injection performance, pilot simulation, and post-pilot core analysis.

3.2 Site Selection and Development

3.2.1 Site Selection

As noted above, two interior inverted five-spot patterns were selected on the McManus lease with one to serve as the test and the other as the control (Figure E-1). The test which is centered on well 208, had been undergoing steam injection since mid-1978, while the control pattern, centered on well 214, had yet to begin steam injection. In fact, at the time the patterns were selected, well 214 had not yet been drilled.

3.2.2 Additional Drilling

At the outset of this project, three wells were drilled. Specifically, well 214 was drilled to complete the control pattern. Also two observation wells, 208M and 214M, were drilled, offsetting their respective central injectors. Cores were cut, although recovery was poor because of the presence of large boulders. Drill cutting samples and side-wall cores were taken to supplement the core data. Also, extensive suites of both open-hole and cased-hole logs were run in both observation wells.

3.3 Reservoir Description

3.3.1 Definition of Layers

The Kern River field formation is a silty sand in which the distinctions between silt, sand and shale are not easily made. Geological correlation is further complicated because few readily identifiable marker horizons exist. Gross thickness of the formation of interest is some 300 feet.

To develop a reasonable picture of the layering in the area, geological cross-sections were prepared and gamma ray and conductivity logs were used to correlate shales. Figure E-2 represents an interpreted cross-section in the test pattern between injector 208 and producer 113B with intervening observation well 208M. As indicated, there are four basic lithologic units with the second and third units further sub-divided into sub-units (2A, 2B, 3A and 3B). The same degree of subdivision is not apparent in the control pattern (see Figure E-3).

3.3.2 Porosity/Saturation Determinations

Porosities and water saturations were determined over a series of depth intervals using several techniques. Tables E-2 and E-3 present porosity and saturation values respectively for observation well 214M.

For each dept interval, core porosities were measured (whole core and/or side-wall). The values determined

from core were then adjusted to reflect the assumption that total pore volume consists of oil and water volume only. Porosities were also interpreted from density/neutron logs and were computed using the Schlumberger VOLAN computer technique.

Similarly, water saturations were determined for each of the depth intervals from core and these values in turn were adjusted. Saturations were also interpreted from the EPT log, the resistivity log and the VOLAN technique.

In general, the porosity as determined from density and neutron logs was lower than that determined from core analysis. Similarly, the log-derived saturations are lower than the corresponding values from core. However, there is good agreement between the EPT and resistivity log values.

Further comments on the interpretation of porosity and saturation values are provided in Section 3.7.2.

3.4 Chronology of SUNTECH IV Experiments

The SUPRI report (Reference 56), describes in varying degrees of detail, three separate tests involving the injection of SUNTECH IV surfactant. These tests, which were carried out in December, 1981, March, 1982 and July, 1982, are summarized in Table E-4.

The interpretability of the December, 1981 test is in considerable doubt. Some 1900 U.S. gallons of 15 percent active SUNTECH IV were injected in conjunction with steam so as to create a four weight percent concentration of the chemical at the sandface. Only a minimal rise in injection pressure was observed, although this result may not have been significant from a reservoir point of view. Specifically, prior to the test, the chemical was inspected and was observed to have a different appearance from that used at an earlier date. Tests indicated that the SUNTECH IV in this batch was only partially in solution and would not generate foam. In an effort to increase its miscibility with water, isopropyl alcohol was added.

During the March, 1982 test, some 2500 U.S. gallons of 15 percent active SUNTECH IV were injected concurrently with steam. Again the mix was such as to create a four weight percent concentration of the chemical at the sandface. A little more than half of the total chemical was injected with steam only. During this period, injection pressure increased to 130 from 75 psig. Following a five day hiatus

in treatment, the remainder of the chemical was injected with steam plus 36,000 SCF of nitrogen. Corresponding injection pressures increased to 150 from 80 psig.

During the latter half of July, 1982, a much larger slug of SUNTECH IV than those employed in the prior tests was injected. Throughout the tests, steam was injected at a rate of some 150 barrels per day. When steam alone was injected, corresponding wellhead pressure was 80 psig. During the addition of SUNTECH IV, this pressure increased to 120 psig. Subsequently, on July 19, 100,000 SCF of nitrogen were injected over an eight hour period. This resulted in an injection pressure increase to 210 from 120 psig. Nitrogen injection was then stopped while SUNTECH IV and steam continued to be introduced into the reservoir. Corresponding injection pressure dropped to 150 psig and then decreased further to 120 psig. A second slug involving 200,000 SCF of nitrogen was injected on July 28th. Pressure increased to 210 from 140 psig. When SUNTECH IV treatment was discontinued on July 29th, the injection pressure began a gradual decrease over the ensuing five days, to 100 psig from 140 psig.

3.5 Distribution of Injected Steam

3.5.1 General

Three basic approaches were used to interpret the distribution of injected steam. One approach involved the use of radioactivity logs at the observation wells. A second involved the use of tracers both to estimate areal conformance and to determine injectivity profiles. The third involved the application and interpretation of well tests. These approaches are discussed below.

3.5.2 Radioactivity Logs

Comparison of gamma ray logs at the injector prior to steaming, with the corresponding logs at the offsetting observation well after steam injection had begun, indicated that steam channels were identifiable. Specifically, after steaming, higher radioactivity counts were observed over some intervals. Spectral logs were run to detect the incidence of radioactive potassium, uranium and thorium. These surveys indicated that the high gamma ray count was due principally to an unusually high level of uranium. To explain this effect, it has been postulated that the steam leaches and redistributes the uranium compounds. The resulting log profiles for injector 208 and offsetting observation well 208M are illustrated in Figure E-2. Strong radioactive anomalies are evident at 208M after the commencement of steam injection which are either not evident or less apparent at well 208 prior to steam injection. The results provide evidence of poor vertical conformance due both to

channelling in higher permeability members and to steam override.

3.5.3 Tracers

I. Responses at Producers--Areal Conformance

Initially, SUPRI attempted inter-well response tests involving the use of radioactive tracers. However, California state limitations on the quantity of tracer which could be used complicated attempts to carry out a successful test. Consequently, a survey program was initiated using chemical tracers. Specifically bromide tracers were injected at the test pattern both before and after the July, 1982 surfactant injection test. For comparison purposes, nitrate tracers were injected in the control pattern at the same times.

Table E-5 summarizes SUPRI's interpretation of the tracer results. The figures suggest that steam flow to well 114 (structurally, the most up-dip well in the test pattern) was increased while the flow towards well 120 was decreased.

II. Injectivity Profiles--Vertical Conformance

Injectivity profiles were obtained at well 208 both before and after surfactant injection in December, 1981, as well as in March and July, 1982. Both water and gas soluble radioactive iodine-131 were employed in an effort to define the injection profiles of both the liquid and vapor phases.

As indicated earlier, the quality of the surfactant used during the December, 1981 test was in question from the outset. Also, the duration of surfactant injection during the March, 1982 test was quite brief (approximately one day). Accordingly, while a definite change in injection profile (i.e., re-distribution of injected fluids among the layers) was observed in the March test, it was quite short-lived. Tables E-6 and E-7 summarize the observed distribution of fluids in the liquid and vapor phases, respectively, before, during and after the July, 1982 treatment, which represents a more sustained test. Prior to surfactant injection the preponderance of injected liquid and gas appears to be entering layer (slice) number 4. During surfactant injection, fluids are largely diverted into layers 3A and 3B. Upon terminating surfactant injection, layer 4 once again accepts most of the injected fluids.

3.5.4 Pressure Fall-Off Tests

SUPRI conducted and analyzed a number of injection well pressure fall-off tests in an effort to monitor the growth of the steam-swept zone.

The pressure transient data were analyzed to determine the volume swept as well as to estimate steam zone transmissibilities and wellbore skin values.

Interpretation of the test results indicated that in the region surrounding well 208, some 3.5 percent of the available reservoir volume had been swept by steam after 3.5 years of injection. The corresponding volume for well 214, which had only been on steam injection for some seven months was less than 0.8 percent of the available reservoir volume.

The interpreted permeability values from the well tests ranged from 160 to 400 md for well 214, and 650 to 1200 md for well 208. This compares with a range of 800 to 1900 md based on core-derived absolute permeability for this formation.

3.6 Production Performance

Figure E-4 illustrates the production performance for the test pattern from June through September, 1982 (i.e., before, during, and after the major treatment with SUNTECH IV).

As shown, pattern oil production rate increases somewhat during the treatment interval in the latter half of July, reaching a peak rate in the post-treatment period of 155 BOPD. This compares with a rate of some 60 BOPD prior to the tests. Water production remains relatively constant at approximately 450 BPD throughout the period of interest.

The temperature response shown is that of producing well 120. Although there was some variation among the four producers in terms of the magnitude and rapidity of temperature response, the curve shown is generally representative of the other wells. As indicated, there is a decrease in wellhead temperature during the treatment period and extending for a short time afterward.

3.7 Commentary on Results to Date

3.7.1 General

Following are some comments on selected aspects of the experiments carried out by SUPRI. It should be emphasized that these comments do not necessarily represent SUPRI's interpretation of the results, but rather constitute our analysis of some salient matters. In addition, we have reserved discussion of some of the test results relating to vertical redistribution of injected fluids (i.e., modification of injection profiles), as well as areal conformance for a later section (E.3) which compares historical performance with basic fluid flow calculations.

3.7.2 Analysis of Core and Log Data

SUPRI determined porosity and saturations using several techniques. For example, porosity was measured by core analysis, and an adjusted porosity value was derived from these core determinations. In addition, porosity was calculated by SUPRI from density-neutron logs and values were generated by a commercial technique (VOLAN). Similarly, raw and adjusted water saturation values were determined from core analysis. Also, saturation values were established using EPT and resistivity logs, as well as the VOLAN interpretation technique.

Comparison of the resulting values obtained using the various techniques illustrates some of the difficulties

associated with reservoir description generally, and with the establishment of basic reservoir parameters specifically.

In analyzing this data, a distinction must be made between average and individual values. For example, it would appear that the VOLAN technique normalizes on average values of saturation and porosity. That is, the average porosity and saturation values generated by the VOLAN technique compare very closely with the respective average values derived by adjusting the core determinations. However, the adjustment of an average value of one set of data so that it accords with the average of another set does not alter the degree of correlation between the two sets.

To examine more carefully the degree to which reservoir parameters calculated from different sources compared with each other, a number of correlation coefficients were calculated. The results are illustrated in Table E-8. As indicated, irrespective of whether comparisons are made among porosities, water saturations, or products of these two variables, the only strong correlation noted was that between water saturation as derived from the EPT log, and water saturation as derived from the resistivity log. All other correlations were very poor.

Inasmuch as the EPT and resistivity log saturation values are in good agreement, and considering that each of these is based on a different measurement principle, they

would appear to be more reliable techniques for determining water saturation. This then, leaves in question the values determined from core analysis and the VOLAN technique in this specific case.

A more general observation based on these results is that care must be taken to compare individual samples or appropriate groups of samples (i.e., over a depth interval), rather than overall average values.

It should be pointed out that although most of the discussion on this matter in the SUPRI report deals with averages, SUPRI have been appropriately cautious in drawing conclusions.

3.7.3 Injectivity

In Section 3.4, increases in wellhead pressure upon adding nitrogen to the steam-surfactant injection stream were noted. However, it is not immediately apparent from the results as presented whether the increase in pressure simply reflects the additional volume being injected or whether it is actually indicative of a reduction in mobility.

In an effort to shed some light on this question, injection rates at sandface conditions were estimated for the cases of both steam only and steam plus nitrogen. After taking into account the different injection pressures associated with each of these two cases, it was determined

that their sandface rates were about equal (approximately 100 MCFD). Considering that a nitrogen-steam mixture would be, if anything, less viscous than steam alone, one would expect no increase in injection pressure. In fact, however, injection pressure increased to 200 from 120 psig. This strongly suggests that the presence of the surfactant resulted in a higher injection pressure (i.e., a lower level of injectivity) than might otherwise be expected. In fact, using an estimated effective reservoir pressure of 70 psig, the calculated pressure drop in the system when nitrogen is injected is more than twice as high as would be expected if mobility had not been altered.

Accordingly, based on observed changes in injectivity during the addition of a non-condensing phase to the steam-surfactant mixture, it would appear that a true reduction in mobility had occurred, at least in the vicinity of the injection wellbore.

3.7.4 Production Performance

As illustrated in Figure E-4, oil production rates increased significantly for a period of one month following injection of the SUNTECH IV in July, 1982. Perhaps of equal significance, in terms of being able to attribute this behavior to the injection of the surfactant, were the wellhead temperature responses at the producers. The substantial and rapid drop in temperature does not appear

to be due to a decrease in total fluid production, since the water rates were fairly constant, and the oil rates were generally increasing somewhat at that time. On the other hand, observed production behavior can be explained in terms of reduced channelling, with a concomitant diversion of flow to previously by-passed portions of the reservoir.

3.7.5 Areal Conformance

Using chemical tracers, SUPRI developed estimates of the amount of steam received at each producer in both the test and control patterns. These estimates are presented in Table E-5 and are expressed both in barrels per day and as a percent of the total pattern steam received at each producer.

In a homogeneous pattern under uniform operating conditions, we would expect 25 percent of the flow to move toward each producer. The degree to which pattern flow approximates or deviates from this ideal situation represents one measure of conformance.

For example, referring to the test pattern, both before and after injection of SUNTECH IV in July, 1982, the respective values of the standard deviation are 23 and 26. That is, relative to a mean flow value at each well of 25 percent, the values at the four wells in the test pattern show substantial dispersion both before and after injection of the surfactant. Thus, one cannot conclude that intro-

duction of the chemical rendered the pattern flow more uniform. This is confirmed by the high value of correlation coefficient (i.e., .96) between the "before" and "after" flow values in the test pattern.

By comparison, in the control pattern, where no SUNTECH IV was injected, the "before" and "after" values of standard deviation are 15 and nine. The corresponding correlation coefficient is .99. Thus the two sets of flow values at the control pattern correlate very strongly as would be expected, since there was no reason to expect a significant change. The slight decrease in standard deviation could reflect some field operating factors. More likely, however, it reflects the uncertainties inherent in the current state of the art of tracer survey interpretation.

In summary, then, on the basis of tracer survey work, we cannot conclude that injection of SUNTECH IV in July, 1982, materially altered the areal distribution of steam flow. This could mean that the improvement of production performance which was observed at the test pattern may have been due to vertical conformance improvements only. At this point we do not know whether the absence of observed improvement in areal conformance reflects a deficiency in the process, the brevity of the slug injection test, or simply the difficulties in interpreting chemical tracer surveys.

3.7.6 Flow Distribution--Interpretation Techniques

SUPRI utilized several special techniques in an effort to determine injected fluid distribution and identify flow geometry. These included radioactive tracers to establish vapor and liquid flow profiles at the injection wells, chemical tracers to indicate well-to-well fluid movement, and Carbon/Oxygen logs to determine fluid saturations through casing.

By and large these techniques are still highly interpretive. However, their potential is considerable, and their continued development would be a valuable addition to the current repertoire of analysis techniques.

It will be helpful if a sound theoretical basis is established for each of these techniques. However, their continued application in field situations, where their results can be correlated with data independently arrived at, will be required if confidence is to be established in their continued use.

3.8 Summary of Performance

To date, several aspects of SUPRI pilot performance suggest that injection of a divertant such as SUNTECH IV will yield beneficial results. Specifically, during injection of the SUNTECH IV slug, and for some time thereafter, oil production rates increased while water production levels remained fairly constant. The observed changed in injectivity profile were substantial and occurred in the direction of increasing vertical conformance. Modification of the vertical flow profile, at least in the vicinity of the injection well, was also consonant with the reduction in injectivity observed during the steam-surfactant-nitrogen treatment. No increase in areal conformance was apparent during the evaluation.

iii) CLD Project

1.0 Background

Work carried out by CLD Group Inc. under a contract with the U.S. Department of Energy included a first phase involving laboratory testing and a second phase consisting of a number of field pilot tests.

The laboratory phase consisted of the following five steps:

1. Static foam testing to evaluate the foaming capability of various chemicals.
2. Laboratory sand-pack tests to evaluate foam effectiveness in reducing permeabilities in a short sand-pack at ambient temperature.
3. Corrosion inhibitor studies to determine the effects of corrosion inhibitors when used in conjunction with air and foaming materials.
4. Laboratory scale steam sand-pack tests to examine the effectiveness of foaming agents in the presence of steam and non-condensible gas.
5. Long sand-pack tests (16 feet) to test foam blocking ability over longer distances and to examine the most efficient method for injecting surfactant.

The results of each of these test steps are summarized in the following section.

Four field pilot tests to evaluate the effectiveness of surfactant-based foam as an ancillary material in a steam drive were carried out at three locations. Two of the tests were conducted at Midway Sunset, one at the San Ardo Field, and one at the Cat Canyon Field.

The locations were chosen to address two problems:

1. Excessive steam channelling through "thief" zones, and
2. Progressive increase in steam flow through oil-depleted, already-swept zones.

Subsequent sections describe these field experiments. However, emphasis is placed on the Midway Sunset tests because of their longer duration and more complete presentation.

2.0 Laboratory Screening Tests (References 57 and 45)

2.1 Static Foam Tests

Foams were screened at room temperature and atmospheric pressure on the basis of two criteria--maximum foam volume attained and the foam half-life (the time necessary for half the initial liquid to drain from the foam). Tests were conducted in the presence of various kinds of water and water-crude mixtures.

In initial evaluations, only 8 of 17 chemicals selected for testing foamed satisfactorily in 0.5 and 1.0 volume percent solutions. Foaming ability of 7 of the 8 surfactants in a two percent KCl solution was maintained at satisfactory levels. Also foam volume was only slightly affected by the addition of 400 ppm calcium. However, the half-life of four of the surfactants was adversely affected by the presence of calcium and was severely reduced for all eight surfactants by the addition of 25 ml of produced water from the Fellows field.

In an additional series of tests foaming ability was evaluated at elevated temperatures for extended periods. As a result of these tests three surfactants were selected as most promising--Thermophoam BW-D, Lakeway 301-10 and Bioterge AS-40.

2.2 Laboratory Sand-Pack Tests at Ambient Temperatures

Room temperature evaluations involving flow through a 40 mesh sand pack were carried out with a number of surfactants to assess their effectiveness in reducing permeability. The two criteria employed in the assessment were level of permeability reduction and duration of effective permeability reduction.

The basic procedure involved first saturating the core with water followed by displacement with nitrogen. A 0.1% solution of the surfactant to be tested was then injected. Permeability was measured as a function of gas throughput at a constant differential pressure.

Initially the surfactant reduced the permeability significantly. For example, Thermophoam BW-D reduced permeability initially by a factor of 20. Permeability remained low until about 500 PV of gas had been injected, after which the permeability increased gradually. After about 800 PV of gas injection, permeability was restored to 50% of the initial value.

These evaluations encompassed not only the three surfactants selected from the static foam tests but three others as well--Amplifoam, Magcofoamer 77 and SUNTECH VII. Although all six surfactants caused a significant reduction in permeability, the Amplifoam and Magcofoamer surfactants were given a lower rating because of the tendency of their

foam blocks to disperse rapidly. SUNTECH VII surfactant was eliminated because of its unavailability commercially.

Based on over-all performance, Thermophoam BW-D was selected for continued testing.

2.3 Corrosion Inhibitor Studies

In anticipation of field tests at Midway Sunset which would use air as the non-condensing gas, the possibility of corrosion had to be considered. Accordingly, the effects of corrosion inhibitors on foam characteristics were investigated.

Two Tretolite inhibitors were evaluated--AO-1 and AO-2, the latter being a dilution of the former with organic solvent. Tests of foam volume and half-life indicated that the presence of solvent in AO-2 rendered it the more deleterious of the two inhibitors.

2.4 Laboratory Steam Sand-Pack Tests

In these tests, which were aimed at evaluating foam performance at elevated pressure and temperature, the surfactant used was 50ml of Thermophoam BW-D diluted to 1.0 volume percent in softened water. The reference case involved injection of steam and nitrogen simultaneously. In a subsequent run, steam and surfactant were injected but with no nitrogen. Throughout the run (some 2,800 PV steam

injected) the pressure differential was lower than that of the reference case.

Surfactant was then injected with steam and nitrogen at 4% of the total flow. The surfactant was injected initially without steam or nitrogen and allowed a five minute incubation period. Effective permeability reduction relative to the reference case was a factor of four at 1000 PV of steam and 2.5 at 2000 PV.

A follow-up test with a second incubation period resulted in a brief five fold reduction in permeability, after which the permeability reduction factor seemed to stabilize at approximately two.

2.5 Long Sand-Pack Tests

Tests with Thermophoam BW-D were carried out on a sixteen foot sand-pack saturated with crude oil from the Fellows field.

Two basic injection methods were used. In one, the surfactant was injected as a slug, followed with steam and subsequently with gas to create a foam. In the second, foam was injected concurrently with steam, after which the steam was discontinued and a slug of gas was injected. Steam injection was later resumed.

The first approach, using 1% Thermophoam BW-D, achieved a reduction in apparent permeability of a factor of 10 after 200 PV of steam injection. When a 5% surfactant solution was injected concurrently with the steam, then followed by a slug of nitrogen after which steam injection was resumed, permeability was reduced by a factor of 7 after 300 PV of steam injection.

3.0 Midway Sunset Field Pilot Experiment (References 57 and 45)

3.1 General

The site selected for the Midway Sunset field pilot consisted of a five-spot pattern, some 5/8 of an acre in area, in an existing and mature steam drive operation whose oil-steam ratio was approaching its economic limit (see Figure E-5). The formation of interest, the Spellacy Sand N, is some 400 ft. in gross thickness, with approximately 100 ft. of perforated interval at the pattern producers. The formation is steeply dipping and exhibits large variations in lithology and oil saturation.

3.2 Test Sequence

The experimental program at this site involved two tests in which Thermophoam BW-D was injected with air to create a flow divertant. Injection of the first treatment proceeded from November, 1980 to May, 1981. The second treatment occurred over the period September, 1981 to January, 1982. Quantities injected during the first treatment, which is referred to as the low concentration test, were 22,000 pounds of Thermophoam BW-D and 2,000 MSCF of air. Corresponding quantities during the second treatment, which is referred to as the replication test, were 55,800 pounds and 2,547 MSCF. Thus, the replication test represented a higher concentration treatment.

3.3 Production Performance

Figure E-5 illustrates the production performance for the pattern (590-21). Oil-steam ratio increases by a factor of seven during the treatment periods, with a correspondingly marked reduction in water-oil ratio. Pattern oil production rate also undergoes a large increase.

A summary of pattern injection and production performance statistics before, during, and after the first treatment is presented in Table E-9. As indicated, from initial response in February through the end of the monitoring period in October, 1981, average oil rate was 71 BOPD compared with 18 BOPD during the pre-test period. In August, 1981, some three months after terminating the first treatment, oil production declined, suggesting some deterioration of the "foam block".

During the twelve month test period from November, 1980 through October, 1981, approximately 20,000 barrels of oil were produced from the test pattern. In addition, production performance improved noticeably in 14 second and third line steam soak wells surrounding the test pattern. Specifically production at second line wells increased to 148 from 59 BOPD. Rates at the six third line wells increased to 110 from 62 BOPD. Estimated incremental oil production from the affected second and third line wells was approximately 50,000 barrels during the test.

The second Midway Sunset test replicated the first in that the same pattern and the same injection fluid were used. In this instance, however, chemical was injected at a higher concentration. For example, 21.9 pounds of chemical were injected per MCF of air, compared to 11 pounds per MCF during the first test.

As illustrated in Figure E-5, all three indices of performance indicate continued favorable response to treatment. Following termination of the second test in January, 1982, and the concomitant shutting in of the southerly pattern producer (well 209), oil production rate underwent a decline. However, it remained fairly steady at some 60 BOPD during the period February through April, 1982 (i.e., in the three month period following the second treatment) even through steam injection was sharply curtailed in March and April.

3.4 Production Distribution--Areal Conformance

Table E-10 presents the average oil production rates for each of the four pattern oil producers for several years preceding the foam injection tests as well as during their operation. The average oil production rate at each of the four pattern producers in the immediate pre-test period as well as during each of the two treatments is summarized in Table E-11. As indicated, most of the production response has occurred at the northerly pattern producer (well 194).

3.5 Temperature Profiles--Vertical Conformance

Figure E-6 illustrates the observed changes in vertical heat distribution at the westerly pattern producer (well 23). Before the treatments, most of the heated fluids were confined vertically to a 50 foot channel situated above the perforations. The channel broadened vertically to 280 ft. after the first treatment, and to essentially the full 400 foot gross interval during the second.

3.6 Commentary on Results

Based on the common indices of production, injection of foam as an ancillary material in a steam drive at Midway Sunset was effective in improving performance, at least during and for some period after the treatments.

In all likelihood, this improvement is a reflection of increases in conformance, and most clearly, in vertical conformance. For example, the vertical broadening of the heated zone at well 23 is quite dramatic.

The influence of areal conformance, however, is less clear. For example, distribution of oil production, as reflected in Table E-11, changes substantially as a result of the treatments. Expressed another way, the calculated correlation coefficients between the percentage flow figures before treatment and those during treatment are very low. However, although the areal flow distribution changes, it is not necessarily more uniform. In fact, if

we use standard deviation as a measure of flow non-uniformity, the respective values for the three periods depicted in Table E-11 are 13, 24 and 9. Thus, areal flow distribution was about as uniform before the treatments as it was during the second treatment, and more uniform beforehand than during the first treatment.

4.0 San Ardo Field Pilot Experiment (References 57, 45 and 58)

4.1 General

The Aurignac sand reservoir at San Ardo is characterized by high transmissibility and a gross thickness in excess of 100 ft. Accordingly, the injection wells have been located on relatively wide spacing (20 acres). Figure E-7 illustrates the pilot pattern and location of the surrounding wells. The oil is 12 to 13 degrees API, with a viscosity at reservoir conditions just under 10,000 cp.

At the same time that foam (Thermophoam BW-D) treatments were scheduled, the steam drive was in an advanced stage. Injection rates were high, and oil-steam ratios were varied but generally low.

Although the injection wells are completed low in the formation, numerous surveys indicate that steam is overriding the oil zone.

In October, 1981, a series of foam treatments was initiated in an effort to divert steam from the existing paths into previously unswept areas.

4.2 Treatment Schedule and Production Performance

The pilot test pattern at this site (Figure E-7) consisted of a central injector surrounded by an inner ring of five producers and an outer ring of eight additional

producers. During the first test, which began in October, 1981, and continued through December, 1981, some 69,200 pounds of Thermophoam BW-D and 4.6 million SCF of nitrogen were injected. During November and December, pilot production averaged some 186 BOPD. In January, the rate dropped to 161 BOPD after which it increased in February and March of 1982 to an average of 230 BOPB. Water cut dropped from 97% in January to 92% in March.

In view of the short duration of the first test, and the encouraging results, a follow up test was initiated to evaluate longer term performance. Injection began in mid-April and was discontinued in mid-June, 1982. A total of 104,000 pounds of chemical and 5.6 million SCF of nitrogen were injected.

Table E-12 summarizes pattern performance throughout the treatment period.

4.3 Injection Distribution--Areal Conformance

A series of tracer tests was carried out in which the total dissolved solids (TDS) content of the produced water serves as the chemical tracer. The formation water in this reservoir has a TDS content of 5,000 ppm. Texaco, the operator, re-use the produced water as steam generator feed water. When steam is generated, the vapor phase will have a very low TDS content. The liquid phase (condensate), on the other hand, will carry the bulk of the dissolved

solids. For example, assuming 65 percent quality steam, TDS in the condensate will be 14,000 ppm.

A program of produced water sample analysis was conducted from September, 1981 through June, 1982, thereby spanning the period of both treatments. Substantial decreases in TDS content were observed in wells throughout the pilot area, suggesting that they were receiving more steam. This is illustrated in Table E-13 for the four inner ring producers.

4.4 Commentary on Results

As illustrated in Table E-12, all of the major performance indices indicate some improvement. Perhaps most dramatic is the reported decrease in water cut. This corresponds to a drop of more than a factor of two in water-oil ratio.

The tracer tests based on produced water TDS represent a resourceful approach to defining the areal distribution of injected fluids. The test results suggested that, following foam treatment, more steam vapor was moving toward the producers. Unfortunately, no individual well production data for the period corresponding to the tracer surveys were published. Accordingly, it is difficult to determine what degree of significance should be ascribed to increased displacement of steam vapor toward the producers. For example, increased steam flow towards a well may be

evidence of better heating in that region, or it may be indicative of the formation of a steam channel from injector to producer, with concomitant deterioration in performance. The ambiguity is compounded by the absence of any data or discussion on the extent to which vertical conformance (i.e., steam override) may have changed as a result of the treatments.

5.0 Cat Canyon Field Pilot Experiment (References 57, 45 and 59)

5.1 Review of Operations

The objective of this test was to determine whether foam could plug a wide high permeability channel between an injector and the nearest updip producer (see Figure E-7) in a deep hot formation containing very viscous oil.

Tracers had indicated that 90 to 95 percent of the injected steam was moving to one producer, ostensibly through a high transmissibility channel at the top of the formation.

From May 1 to mid-June, 1981, varying schedules of Thermophoam BW-D, steam and nitrogen were injected.

Although water cuts decreased in the pattern wells, no significant change was observed in the water cut of the key producer.

5.2 Commentary on Results

The authors conclude that the treatment did not adequately block the steam channel, in spite of some positive indications. There is an implication that the size of the foam treatment may have been too small.

Unfortunately, the paucity of published data precludes independent interpretation.

iv) CORCO Project (References 53, 54, 55 and 47)

1.0 Background

The principal objective of this DOE-sponsored project, conducted by Chemical Oil Recovery Co. (CORCO) on a Petro-Lewis lease, was to assess the economic feasibility of improving performance in a conventional steam drive using ancillary materials to improve sweep efficiencies. To this end, steam foams were evaluated as divertants in a group of field pilots in the North Kern Front Field in California. It should be noted that these field experiments involved steam plus a divertant, with no non-condensing gas. These are in contrast to the tests supervised by SUPRI and CLD which included either air or nitrogen injection.

The experiments involved six ten-acre inverted nine spot steam drive patterns (Figure E-8). Prior to commencement of these experiments some 24 percent of the 4.4 million barrels of oil originally in place had been produced under primary and secondary techniques, including conventional steam drive.

Steam flood performance in these patterns is characterized by a lack of heating down-dip (i.e., westward) and significant temperature responses at the up-dip (eastward) producers. These responses together with a number of instances of casing blows indicated the onset of steam channelling.

The field pilot experiments were aimed at evaluating two types of divertants to mitigate steam channelling. The first, COR-180, produces a foam in association with a gas or vapor phase. The second, COR-GEL, is a combination of the foaming chemical with a cross-linking polymer. The polymer encapsulates the foaming chemical so that foam formation is delayed for some time (i.e., until after the polymer breaks down at the high temperatures associated with the steam), thereby facilitating deeper penetration or foam into the reservoir.

2.0 Reservoir Characteristics

The principal productive horizon in the North Kern Front leases is the Upper Miocene age Chanac sand. The sand is located at an average depth of 1570 ft., and has a net sand thickness of 42 to 52 ft. Initial oil richness was some 1640 barrels per acre-foot. Although permeabilities average some 2200 md, they can vary from 15 to 12,000 md in a single producing interval.

The 13 degree API crude is extremely viscous, and contains small volumes of gas.

The reservoir is a structural fault trap with an edgewater drive. Formation structure is generally most pronounced in an east-west direction with an eastward upslope trend (i.e., with the downdip edgewater drive to the west). Structural variations in the north-south direction are relatively small.

3.0 Base Data

Figure E-8 illustrates the steam flood patterns in each of the two pilot areas. Each area consists of three adjacent nine spots. Individual wells are on 2.5 acre spacing, so that each nine spot pattern encompasses 10 acres. At the time of these experiments, the Mitchel patterns were in a more advanced stage of depletion than the Witmer patterns, having produced 54 percent of their original oil-in-place.

To establish background levels prior to the use of chemical tracers, fluid samples were gathered from all producers and analyzed for levels of nitrate, bromide, iodide, and thiocyanate. Corresponding tracers were then introduced at the injectors and their arrival times and concentrations were monitored at the producers. Early arrival of tracers at the eastward producers confirmed the observed tendency toward channelling in the up-dip direction.

Each of the six injection wells was surveyed to obtain injection profiles. This involved the use of both gas and water soluble radioactive iodine (I-131). There are a number of lenses or members in the Kern Front oil sand which may or may not be separated by shales. The tracer-generated injection profiles indicate that each lens which is present accepts steam at a distinctive rate.

4.0 Design of Treatments

The field experimental approach was to subdivide the pilot areas into three sets of two patterns each. The patterns surrounding the Mitchel 63 and Witmer B2-5 injectors were designated for treatments with sequential slugs of steam foam-polymer combination (COR-GEL). Patterns Mitchel 65 and Witmer B2-3 were slated for sequential slugs of steam foam (COR-180). The remaining two patterns, Mitchel 67 and Witmer A2-7 would receive no treatment and would thereby serve as control patterns.

The COR-GEL treatments began at Mitchel 63 and Witmer B2-5 injectors in March and May, 1980, respectively. By the end of September, 1982, the corresponding volumes of chemical which had been injected in weekly slug treatments into each of the two wells were 39,075 and 38,085 U.S. gallons.

Slug treatments with COR-180 began in January, 1980 at Mitchel 65 and in March, 1980 at Witmer B2-3. The COR-180 was injected as an aqueous solution containing approximately 60 percent active foaming agents. By the end of September, 1982, respective quantities of chemical injected into Mitchel 65 and Witmer B2-3 were 101,250 and 67,950 pounds.

5.0 Pilot Performance

5.1 General

The effectiveness of the divertants employed in these experiments was assessed in terms of three types of information--areal conformance, vertical conformance, and injection/production performance. Chemical tracers and production response data were used to help characterize areal conformance. Injection profiles using a radioactive tracer were obtained to help establish the degree of vertical conformance. Production and injection data averaged over sufficiently long periods to reduce scatter provided the most direct indices of performance. In this latter regard, oil-steam ratio proved to be the most reliable performance index.

5.2 Tracer Surveys--Areal Conformance

Table E-14 summarizes the results of chemical tracer tests carried out both prior to and during foam treatments at the Witmer patterns. Witmer B2-3 received COR-180, Witmer B2-5 received COR-GEL, and Witmer A2-7 received steam only. Shown are the times at which tracer was first detected at each producer, as well as the times at which the peak concentrations were observed.

These results, together with production performance data, were used by CORCO to interpret areal distribution of injected fluids. On the basis of these studies, the authors concluded that areal conformance was improved in

the two Witmer patterns which were undergoing treatment. Based on similar data at the Mitchel 63 pattern, they concluded that it toohad experienced an increase in areal conformance.

It was observed that increased areal conformance in the Witmer patterns was also evident in an increased oil-steam ratio. No such correlation was apparent at the Mitchel patterns. An examination of production data indicated that approximately half of the original oil in place in the treated Mitchel patterns had already been produced. This compared with 30% for the two Witmer patterns undergoing treatment. Accordingly, it was postulated that although the pattern of steam flow had been altered in the Mitchel patterns, the steam had not contacted areas of higher oil saturation.

5.3 Injection Profiles--Vertical Conformance

Injection profiles were obtained both before and after foam treatments using gas and water soluble radioactive iodine (I-131) as the tracer. These profiles indicated that injection across the sand interval was not uniform, with each lens or sand member accepting fluids at a distinctive rate. These observations also demonstrated that injection profiles are altered as a result of the treatment. This is illustrated in Table E-15 which presents the injection profiles at Mitchel 63 just before scheduled treatment, and for the two days following the treatment, CORCO con-

cluded that injection profiles are altered as a result of the treatment. CORCO also reported increases in injection pressure associated with the treatment and lasting several days beyond the treatment period.

5.4 Production Performance

Table E-16 presents the average oil-steam ratios as reported by CORCO both before and after treatments had been carried out at the Witmer B2-3 pattern. The data are as of March 1981. Comparisons with the control pattern, Witmer A2-7 indicate that prior to treatment the B2-3 pattern was, if anything, a poorer performer than the control pattern. After treatment, average oil-steam ratio of the test pattern was some 46% higher than that of the control pattern.

The beneficial effects which appear to be associated with the COR-180 and COR-GEL treatments at the Witmer patterns are also illustrated in Table E-17 which presents average quarterly oil-steam ratios at all six patterns.

6.0 Commentary on Results

Examination of tracer velocities (first arrival and peak) indicates that, in a given pattern, there is very little correlation between values before and during treatment. From this it might be inferred that the distribution of fluids within a given pattern has changed significantly as a result of the treatment. However, this apparent change in fluid distribution, which is indicated for both of the Witmer patterns undergoing treatment, also appears to be true for the control pattern. For example, if the tracer velocities in response to treatment were totally different from those measured prior to treatment, we would expect a zero correlation coefficient. On the other hand, if there were a perfect proportionality between the two values, the correlation coefficient would be unity. Comparing first arrival velocities before treatment for the Witmer B2-3, B2-5, and A2-7 patterns with the corresponding velocities during treatment, the respective correlation coefficients are 0.43, -0.06, and 0.28. Analogous calculations based on peak velocity yield similar results. Thus it is difficult to draw any firm conclusions about areal conformance based on the tracer survey results alone.

Table E-15 summarizes the interpreted vapor and liquid injection profiles at Mitchel 63. Calculations or correlation coeffecients to estimate the degree of correspondence or difference between the injection profiles on successive days indicates that by the second day of treatment

(June 25, 1980) the vapor injection profile has altered significantly. This could suggest that injected fluids have been re-distributed vertically as a result of the treatment. Unfortunately, no analogous injection profiles were published for the control patterns. Accordingly, it is difficult to draw a firm conclusion on this matter.

Average quarterly oil-steam ratios for each of the six patterns from 1979 through the third quarter of 1982 are presented in Table E-17. These data have been summarized in Table E-18 in terms of oil-steam ratio before and after treatment. As indicated, the two Witmer patterns which underwent treatment appear to have experienced a significant increase in oil-steam ratio relative to the control pattern. The Mitchel patterns, on the other hand, experienced no such improvement.

If CORCO are correct in surmising that the failure of the Mitchel patterns to respond to treatment is a result of their advanced state of depletion, then the favorable response at the Witmer patterns is an encouraging development.

The interpretation difficulties with this project as described above, illustrate graphically the need for several types of supporting information as well as the importance of control patterns in establishing the significance of this kind of experimental data.

v) CORCO-Union Field Experiments (Reference 60)

1.0 Background

Over a two year period beginning in 1973, a series of tests in the Midway Sunset field were carried out using COR-180 in conjunction with 75 percent quality steam to generate a foam for flow diversion. The unique feature of these tests was that foam was used as a flow divertant in cyclic stimulation operations rather than in a steam flood.

2.0 Reservoir Description

The target zone for the experiment was the Potter sands located at a depth of 1400 feet. Average formation thickness is some 400 feet with permeabilities in the range of 3000 md and porosities of approximately 35 percent. Crude oil gravity is in the range of 8 to 16 degrees API. The dominant recovery mechanism is gravity drainage.

3.0 Treatment Procedure and Test Results

The basic treatment procedure involved injecting 75 percent quality steam for 24 hours. This was followed by some 80 U.S. gallons of COR-180 and another 24 to 72 hours of steam. Subsequently, a final slug of COR-180 was injected, consisting of between 80 and 100 U.S. gallons.

Some 21 wells were cyclically stimulated in this manner over a two year period, beginning in 1973. However, the investigators indicated that they were able to evaluate only four of the 21 wells because of confounding factors

such as excessive heat injection, inter-well interference, down-time, and mechanical problems.

Based on aggregate performance of the four wells which were deemed analyzable, it was estimated that the foam treatments generated some $34,000 in incremental net income at a cost of $2,800. All chemical costs were estimated to have been paid out by 80 barrels of incremental oil.

4.0 Commentary on Results

Examination of the production response data under cyclic stimulation appears to confirm that, at least in some instances, an improvement in performance and specifically in oil-steam ratio and oil rate, was achieved on those cycles involving treatments with COR-180. However, in view of the confounding factors alluded to by the investigators, a more critical analysis of the production performance data is difficult and probably unjustifiable.

One instance of vertical heat distribution before and after treatment was presented. The method by which this heating profile was obtained is referred to as a temperature-tracer survey. However, no further details on either the measurement or interpretation techniques are provided. Taking the survey data as presented, calculation of a correlation coefficient between the "before" and "after" profiles indicates that there is a significant difference in the

vertical distribution of heat. This, in turn, suggests that the COR-180 was effective in re-distributing the injected steam.

3. Divertant Flow Behavior--Specific Considerations

a) General

In Section 2b), laboratory studies of foam characteristics and flow behavior were reviewed. That review included some discussion of certain ambiguities regarding the diverting abilities of foams under various conditions. In this section, highly simplified mathematical flow models are utilized to investigate some specific aspects of field pilot performance involving the use of a divertant.

The approach taken is based on the assumption that foam flow is poorly understood. Accordingly, history matching of an observed instance of pilot performance is not used to "validate" the model. Rather, the discrepancy between model or other calculative techniques on the one hand, and field pilot performance on the other, is examined to identify or illustrate gaps in our knowledge of foam flow behavior. We refer here to gaps which go beyond a simple elaboration of the model along existing lines of knowledge.

b) Description of Mathematical Model

A simplified piston-like flow model based on an analytical approach was developed for this specific application. Employed in the cross-sectional mode, the model represents a sequence of non-communicating layers, each with a different set of reservoir properties (e.g. permeability, porosity, and thickness). Cross-sectional area is varied to reflect flow from injector to producer in a five-spot pattern. Displacement is piston like and isothermal.

Alternatively, the model can be employed in an areal mode. Fluid displacement is along stream tubes in a five-spot pattern across which there is no lateral flow.

The model describes displacement through the layers or stream tubes with as many as three fluids present, each with a distinctive mobility. Thus, for example, a heavy oil might be displaced by steam for a certain period after which foam is injected.

Strictly speaking, we do not understand to what extent a mobility reduction due, say, to foam is attributable to reduction in permeability or increase in viscosity. However, for simplicity of discussion, we will represent the reduced mobility of foam in terms of an increased effective viscosity.

When used properly, the utility of this kind of model can be considerably greater than its simple structure would suggest. For example, under some circumstances, it is possible to demonstrate the presence or absence of a given phenomenon by varying parameters over a range of extreme values (i.e., by bracketing).

c) Alteration of Injection Profiles

In their report of pilot experiments involving the use of foam (Reference 56), SUPRI presented injection profiles at their test pattern. These were obtained by interpreting radioactive tracer surveys before and in response to foam treatment. Their results, which were obtained for both the vapor and liquid phases, are summarized in Table E-19. The flow was distributed among three layers referred to in descending order as 3A, 3B, and 4. Irrespective of whether we consider the vapor or the liquid phase, the same general behavior is observed. Specifically, prior to foam treatment, layer 4 accepts approximately 80% of the injection with the remainder going to layers 3A and 3B. Following foam treatment, the proportion of injected fluids entering layer 4 has been reduced to 10% with the remaining 90% distributed more or less evenly between layers 3A and 3B.

Using the vapor injection profiles from the SUPRI test pattern, the model was used to depict a three layered five-spot. Transmissibilities were assigned to the layers in the model so as to simulate the observed pre-treatment vapor injection profile. That is, layers 3A, 3B, and 4 in the model accepted respectively, 7, 11 and 82% of the injected steam (Table E-19).

A series of runs was then made in which the quantity and viscosity of the foam were increased in an

attempt to simulate the injection profile observed after foam treatment. The results are summarized in Table E-20. In all of these runs, in an attempt to accentuate the effect of the foam, the viscosity of the displaced phase was maintained at an artifically low value of 0.5 cp. As indicated in Table E-20, even when foam viscosity was assumed to be 1000 cp and the volume of foam was some ten times higher than that actually injected, the vapor phase injection profile was modified only slightly from its pre-treatment level. Stated another way, even fairly extreme variations in foam viscosity and quantity, together with an artificially lowered displaced phase viscosity (0.5 cp), were insufficient to achieve even an approximation of observed performance with the model.

Before proceeding further, it is essential to examine the conventional limitations of the model to determine whether they are at the root of the problem. The principal limitations consist of the absence of relative permeability effects, crossflow, and heat transfer.

Attempts to vary the foam relative permeability to achieve a match of the injection profile are essentially equivalent to increasing foam viscosity for purposes of this exercise. As already illustrated in Table E-20, this type of parameter variation over a large range fails to achieve the required match.

We can try to approximate the actual injection profile, by invoking crossflow and determining what the implications are. The observed change in injection profile occurred very rapidly (i.e., over the course of one week). To have achieved this response, 1500 cp oil would have had to migrate vertically at a velocity of approximately one foot per day. Even if we assume that effective vertical permeability is equal to the maximum horizontal permeability measured from well test analysis (i.e., 1200 md), and that on the average, the oil is required to migrate only ten feet vertically, we calculate that a pressure gradient of some 2000 psi would be required in the vertical direction to achieve the desired rate of crossflow. Inasmuch as maximum injection pressures in the system were generally less than 200 psi, it is most unlikely that crossflow would account for the observed change in injection profile.

Vertical heat migration could proceed no more rapidly than convective transport (i.e., crossflow). Accordingly, it is highly unlikely that the absence of this mechanism from the model constitutes a limitation from the point of view of this specific simulation.

As discussed earlier, laboratory studies carried out by at least two groups of investigators (References 40 and 42) indicated that mobility reduction by foam is more effective in higher permeability porous media. This mechanism was incorporated into the model and the observed redistribu-

tion of the injection was matched. Table E-21 shows the resulting relationship between effective foam viscosity as determined for each layer by the history match, and the permeability of that layer. As indicated, the matching procedure results in an outcome which need not have been, but in fact turns out to be consistent with the assumed mechanics. This is, the effective foam viscosity (i.e. foam blocking capability), varies directly with the absolute permeability of the layer.

The significance of this outcome must be assessed carefully. On the one hand, attainment of a history match by allowing foam blocking ability to vary from layer to layer yielded a result which was consistent with the findings of at least two groups of investigators (Reference 40 and 42). On the other hand, considering that another laboratory investigation (Reference 37) drew the opposite conclusion (i.e., that foam blocks more effectively in lower permeability porous media), it would be premature to conclude that an apparent correspondence between model matching results and the findings of some investigators necessarily validates either one.

Notwithstanding these and other unresolved matters related to foam behavior, the modeling work has proved to be of value in that it has helped identify important issues for future resolution by appropriate experiments. In the specific example under discussion, it will be essential to

characterize the blocking abilities of foams as a function of permeability if this process is to be understood.

Just as the ability to match historical performance by invoking certain flow mechanisms does not necessarily verify those mechanisms, the converse is also true. Thus, the inability of crossflow to account for the observed redistribution of injection does not mean that crossflow does not exist. Indeed, while it may be of little importance in accounting for observed behavior over the short span of events under consideration here, its long term significance in the recovery process may be considerable.

d) Areal Conformance

In the pilot studies discussed previously, there is, unfortunately, little clear cut evidence of increases in areal conformance with consequent improvement in production performance. Accordingly, it is difficult to follow an analogous procedure to that used in the foregoing section dealing with vertical conformance.

Not surprisingly, calculations using the model in an areal streamtube mode suggest that injection of foam should increase areal conformance. For example, it steam is injected into a 100 cp oil, areal sweep efficiency at breakthrough is 40 percent in a five-spot pattern. Continued injection with steam would increase sweep efficiency by only four percent to 44 percent. If however, 100 centipoise foam is injected into the pattern following steam breakthrough, a greater increase in sweep efficiency is realized. For example, if a foam slug equivalent to 12% of the pore volume is injected, calculated areal sweep efficiency is increased by 9% to a value of 49%.

Although this type of calculation suggests that areal conformance can be improved by injecting a divertant, the current state of the art precludes our drawing any conclusions on the matter. Again, the difficulties we face in deciding what levels of expectation to set involve a lack of understanding of the fundamentals of flow divertant behavior. In addition, even if we knew what to expect, the

only way to measure improvements would be in the field. However, our current field interpretation techniques for areal conformance, such as the use of chemical tracer surveys, will require much more development, before they can be considered reliable.

UPC

F. FUTURE R AND D EFFORT AND PRIORITIES

1. General

Based on our analysis of the current state of the art with respect to enhanced oil recovery generally, and conformance specifically, a number of problems have been identified which we believe merit attention. Following is a brief description of those problems, suggested priorities associated with them, and some discussion of future R and D programs directed towards their solution.

2. Unresolved Problems

a) Flow Fundamentals--Divertants

Perhaps the most prospective technique for conformance improvement now being pursued by industry involves the use of divertants, such as surfactant-based foams, and cross-linking polymer gels. However, notwithstanding encouraging results in a number of field pilot tests, the mechanisms by which foams improve conformance are poorly understood. So fundamental are some of the gaps in our knowledge, that at this time we are not in a position to formulate basic mechanistic concepts with confidence, let alone equations and models.

Following are some important questions, which need resolution:

1) How do the permeability and permeability distribution of a porous medium affect a foam's blocking effectiveness

and stability? Most importantly, do foams block higher permeability media more effectively than they do lower permeability media? Does blocking effectiveness depend on whether a sand is consolidated or unconsolidated? Does the relationship between permeability and blocking effectiveness change, depending on the nature of the foam (i.e., foam quality or texture)? Does the presence of oil or brine affect this relationship?

2) Within a given porous medium, how do variations in each of the following parameters affect the blocking effectiveness and stability of a foam:

   i) Foam quality
   ii) Foam texture
   iii) Presence of oil
   iv) Presence of brine
   v) Surfactant concentration
   vi) Presence of a polymer gel additive (viscosifier)

3) How do the permeability and permeability distribution of a porous medium affect the blocking effectiveness and stability of cross-linking polymer gels? Does the presence of oil or brine influence the efficacy of these gels?

4) Having regard to the above questions, what are the corresponding behavioral characteristics of gel-encapsulated foams?

b) Effectiveness of Divertants in Canadian Heavy Oil and Oil Sands Situations

How will divertants perform under actual field conditions in a variety of situations?

Analysis of the California steam pilot results (section E) appeared to provide stronger evidence of improvement to vertical conformance with less conclusive indications of areal conformance improvement. Is this simply an anomaly of sampling or interpretation, or can we expect a similar result in our reservoirs?

The results of divertant injection at the California steam pilots were generally very encouraging. However, their long term effectiveness has yet to be established. This same question of divertant longevity would need to be addressed in the process of their evaluation in Canadian situations.

c) Timing of Enhanced Oil Recovery

There is some evidence to suggest that ultimate oil recovery in situations where an EOR process follows after waterflooding may be less than that which would have been achieved had EOR been implemented without any intervening waterflood stage. The potential technical, economic, and policy implications surrounding this matter are considerable. If, indeed, the interposition of a waterflood phase is prejudicial to ultimate recovery, then those waterfloodable

pools which have either not yet undergone, or are not in an advanced stage of waterflooding, should be assessed to establish their eligibility for EOR operations. Of course, one of the principal attractions of waterflooding is that it represents a relatively inexpensive means of sustaining or increasing production. Accordingly, if subsequent findings confirm that it is technically advisable to omit or minimize the waterflooding stage in favor of EOR, but that to do so could incur an economic penalty, then policies which provide incentives for EOR projects will have to be developed and implemented.

d) Well Configuration and Operation

To a large extent the effect on conformance of well configuration and operation is site specific. While this may compromise our ability to make generalizations about well spacing, completion interval, pattern configuration, well orientation, and well operating strategy, it does not alter the fact that these represent important considerations. For example, in a given field situation, can poor areal conformance be rectified to any substantial degree by means of operating strategies at the existing wells? If not, and if infill drilling is indicated as an alternative, should the infill wells be drilled during active operation at the initial wells (i.e., should operations proceed on closer spacing)? Or, should infill drilling await the natural termination of operations at the existing wells so that, for

example, the original effective spacing is maintained, but with an entirely new set of wells?

In an appropriate oil sands situation, will it be preferable from the point of view of recovery and economics to conduct thermal recovery operations using horizontal wells?

e) Vertical Transmissibility

Although there have been isolated efforts to determine vertical transmissibility in individual instances, by and large this remains a neglected area. In a horizontal displacement, vertical transmissibility will be important if crossflow has the potential to influence performance significantly. Even in those situations in the oil sands where vertical fractures are induced during injection, the character of subsequent matrix flow at some distance from the fracture face may be affected by vertical transmissibility. Also, in processes where gravity drainage plays a key role, which would include but not be confined to horizontal wells, vertical transmissibility will be a correspondingly important factor.

f) Flow Fundamentals--Emulsions

Broadly speaking, foams and emulsions share certain characteristics in common in that they can both be regarded as dispersions. Considering industry's longstanding interest in emulsions, it would be useful to compare the blocking effectiveness of oil-in-water emulsions with that of foams.

g) Flow Fundamentals--Polymers

Polymers create a resistance to flow within a porous medium. However, as with foams, there seem to be some contradictions in the literature regarding relative effectiveness of the polymer as a function of permeability of the medium.

h) Clays/Fines

Phenomena such as swelling of indigenous clays or hydrothermal synthesis of swelling clays have been observed both in the laboratory and in the field. However, the ramifications of these phenomena for field operations require further clarification.

For example, in those instances in the field where montmorillonite synthesis has been observed, has it resulted in a significant change in injectivity, productivity or recovery?

i) Selective Mobilization--Electrical Conduction Heating

Does electrical conduction provide a practical means of increasing conformance by selectively heating and facilitating oil recovery from those portions of a reservoir which are bypassed by fluid displacement processes?

3. Priorities

a) Divertants

Among the proposed alternative techniques for increasing recovery through conformance improvement, divertants are the most advanced in their development to date, notwithstanding the many unresolved questions surrounding them. A further attraction of divertants is that their application on a field basis is relatively uncomplicated in terms of special field facilities. Also, divertants offer the prospect of being the most versatile alternative in that they are potentially applicable across the spectrum from conventional oils to heavy oils, and possibly to oil sands. Accordingly, development and evaluation of divertants should be assigned the highest priority in Canada's EOR effort.

b) Timing of EOR

In those conventional oil operations where waterflooding is being or will normally be employed, the promptness with which EOR techniques are introduced could have a strong bearing on ultimate recovery. The timing of EOR and the concomitant question regarding the advisability of waterflooding, is an important matter, and should be given immediate attention. It is ranked second to the problem of divertants only because successful development of divertants for application in conventional oil reservoirs may help reduce the impact of waterflooding inefficiencies.

c) Well Configuration and Operation

Consideration of well configuration and operation have generally not been given the attention they deserve. It is not unreasonable, and in fact may be instructive to view the strategy of well configuration and operation as one category of EOR technique, just as one might regard divertants and electrical heating. For example, if it were possible to attain significant increases in conformance by choice of completion interval, and/or well operating strategies, in, say, a steam injection operation, this might represent an economically attractive EOR alternative.

Included as a special but potentially important case of well configuration is the application of thermal recovery, and particularly steam injection, in horizontal wells.

d) Vertical Transmissibility

One of the significant determinants of vertical conformance is vertical transmissibility within the reservoir. The importance now attached to questions of gravity segregation and override, vertical crossflow and diversion, is such that further effort aimed at quantifying this parameter is warranted.

e) Flow Fundamentals--Emulsions & Polymers

Industry has expended considerable effort in laboratory and field projects involving polymer flooding as well as the application of caustic to create emulsions. However, some relatively fundamental questions regarding their respective mechanisms still remain. Resolution of these matters will not only aid in characterizing emulsion and polymer flow, but may, by comparison, enhance our understanding of foams and gel encapsulated foams.

f) Clays/Fines

Clays, whether indigenous or synthesized, are a common feature of Canada's heavy oil and oil sands areas. Accordingly, it is important that the industry remain cognizant of their presence. However, the specific circumstances under which they have a significant influence on field performance have yet to be defined.

g) Selective Mobilization (Electrical Conduction Heating)

Techniques which have the potential to mobilize oil in a selective manner, such as electrical conduction heating, merit attention and continuing evaluation. However, we have assigned it the lowest priority among the items recommended for future investigation, because its success may ultimately be dependent upon the success of displacement-related techniques such as divertants. Thus, electrical heating may selectively mobilize oil contained in a lower permeability zone. However, unless a displacement technique

can be developed which will then drive the oil from this zone, instead of seeking some higher mobility path, the anticipated benefits of the selective process may not be realized.

4. Directions and Programs for Future R and D Effort

a) Divertants

A strong and immediate effort needs to be mounted to understand and evaluate divertants. This should be carried out with concurrent efforts in the laboratory and field. In this regard, several matters deserve emphasis. Firstly, laboratory and field efforts should be concurrent, and not consecutive, as insight at both levels will be required simultaneously. Correspondingly, we believe that it is a fallacy to expect those insights to develop in an orderly manner, beginning with the laboratory and moving unilaterally outward to the field.

The thrust of the laboratory work should be toward understanding the fundamental mechanisms underlying divertant behavior. Flow experiments should be kept simple, with the emphasis on control and interpretability, including visualization where possible. Thus, for example, flow and displacement tests could utilize cores or parallel core arrangements. Also, micro-models may be useful in strictly controlling pore geometry, and visualizing the associated flow mechanisms.

The requisite concurrent field effort can and should start immediately in heavy oil and oil sands pilot operations involving steam injection (both cyclic stimulation and flooding). The effort should then be extended to conventional oil operations which are under waterflood and in which conformance problems have been identified.

b) Emulsions and Polymers

It may be appropriate to carry out studies of the fundamental flow behavior of emulsions and polymers in conjunction with the laboratory work on divertants. If not, then separate programs of experiments to examine pore trapping of emulsions and polymer mobility reduction as a function of permeability should be initiated. However, while these are important areas, the work on divertants should be accorded higher priority at this time.

c) Timing of EOR

Approaching the question of when EOR should be implemented, and whether waterflooding should be discontinued, or not implemented (if that option is available), requires special care. When approached in depth, this is a site specific question. That is, the answer depends upon the specific characteristics of each reservoir, as well as associated operating considerations. Accordingly, one alternative is to simply urge operators within industry to review their situations, making predictions under alternative modes of development, and then decide on the advisability and timing of EOR schemes.

Unfortunately, however, there is a danger that in many cases this approach will be self-negating. Calculations which demonstrate that it is technically advisable to implement EOR in preference to waterflooding may also indicate that it is economically disadvantageous to do so.

To forestall this possibility, the question should be formulated as follows:

i) When EOR is compared to waterflooding in a given situation (i.e., for a given set of assumptions), is there an immediate economic incentive in proceeding early to EOR operations?

ii) If there is not, what types of policy would create the necessary incentives?

If these questions are used as the basis for an approach, then initial efforts in this direction might best consist of "pencil and paper" studies of a reservoir/economics nature.

d) Well Configuration and Operation

In view of its site specific nature, research related to well configuration and operating strategy will require a large component of field experimentation.

In vertical wells, choices of spacing, pattern configuration, and completion interval, as well as of operating strategy, underly every oil recovery operation. However, as suggested earlier, to the extent that their manipulation can increase conformance, they represent a valid alternative among EOR techniques. Accordingly, when an operator evaluates one of the more exotic EOR alternatives, it should be compared to a "fall back" position in which the

exotic process is deferred, and, for example, infill drilling or revised well operating strategies are assumed.

Field effort aimed at evaluating the efficacy of horizontal wells in steam injection operations has received some attention within industry, and should be pursued to identify the specific circumstances under which it is the preferred choice of well orientation.

e) Vertical Transmissibility

Efforts aimed at quantifying vertical transmissibility should be coordinated along two distinct but complementary directions. Firstly, geology, petrophysics, and reservoir engineering disciplines should be combined with a statistical approach to determine how much can be inferred about vertical permeability from core permeability measurements, combined with core and log information on the occurrence and correlatability of barriers to vertical flow. Secondly, reservoir engineering techniques could be used to infer vertical transmissibility from field data. One approach, for which there are precedents in the literature, involves conducting and analyzing pressure transient tests in which a vertical component of flow is induced. A second approach entails history matching of observed gravity override, such as in a steam injection operation. As with any reservoir engineering calculations, the sensitivity of the resulting interpretation to the assumptions employed would need to be determined so that some confidence can be placed in the answers.

f) Clays/Fines

Now that the potential for the occurrence of clay or fines related phenomena has been identified, the extent to which these phenomena actually cause problems of practical significance (or perhaps yield a coincidental benefit) has to be established. To this end, some field-oriented programs should be initiated.

One such program, which has the advantage of relative simplicity, would involve injecting, as an additive to steam, a suitable chemical, such as ammonia, into wells with injectivity or productivity problems in which swelling clays may be implicated. Mitigation of the problem might have immediate practical benefit and would provide both information and encouragement for follow-up effort.

In addition, post-test core hole programs should be considered in those pilot operations where either clays or fines are suspected to have caused problems. Certainly, if, for whatever reason, post test coring is carried out, clay analyses should be performed. In view of reservoir variability and the advisability of having a basis for comparison, post-test coring locations should be close to previously cored or logged wells.

g) Selective Mobilization (Electrical Conduction Heating)

Further pursuit of techniques such as electrical conduction heating should be confined at this time to "pencil

and paper" studies, and bench scale experiments. So long as electrical conduction is used as a heating technique, its impact on recovery is still dependent upon the efficiency of some subsequent fluid displacement process. To the extent that those processes are inefficient because of poor conformance, the value of the pre-heat phase is correspondingly diminished.

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TABLES

TABLE D-1

Skull Creek Newcastle Sand Unit Polymer Flood
Injection Profiles Before and After Polymer
Bottom Perforations

Depth Interval ft.	% of Total Injection into Interval	
	Before Polymer Injection	7 Months After Polymer Injection
2961 - 64	95	
64 - 71	0	
2961 - 63		6
63 - 65		18
65 - 67		12
67 - 69		22
69 - 71		26

TABLE D-2

Selected[1] Projects from EOR Survey
Oil and Gas Journal, April 5, 1982

Process	No. Projects	Total bopd	Enhanced bopd	Enhanced/ Total	No. of Projects which are profitable	% of Projects which are profitable
Non - Thermal						
Micellar - Polymer	5	325	230	0.71	0	0
Polymer	15	6,267	1,467	0.23	8	53
Caustic	2	700	580	0.83	1	50
CO_2 Miscible	8	71,633[2]	21,743[2]	0.30	4	50
Hydrocarbon Miscible	3	3,332	2,227	0.67	1	33
Flue Gas	2	55,200	35,200	0.64	2	100
Total Non-Thermal	35	137,457	61,447	0.45	16	46
Thermal						
Steamflood	49	215,872[3]	206,169[3]	0.96	40	82
Cyclic Steam	29	52,256[3]	48,322[3]	0.92	28	97
Combustion	10	10,178	9,619	0.95	10	100
Total Thermal	88	278,306	264,110	0.95	78	89
Grand Total	123	415,763	325,557	0.78	94	76

1. U.S. projects reported as promising or successful and for which production figures are furnished.
2. Major portion represents Sacroc Unit, Texas.
3. Major portions represent California heavy oil areas.

TABLE E-1

Range of Gelation Times
for
Three Cross-Linking Polymers

Gel	Range of Gelation Times and Temperatures				Typical
	Gel Time	Temp, C	Gel Time	Temp, C	concentration, %
Geoseal TM (Borden)	10 sec.	5	100 hrs	65	5 to 35
MT (Borden)	10 hrs.	50	1000 hrs.	150	10 to 30
HT (Borden)	1 hr.	150	150 hrs	250	3 to 10

TABLE E-2

POROSITY ESTIMATES IN WELL 214M

Depth, ft	Porosity			
	core	adjusted core	this study	VOLAN
192-220	0.29	0.22	0.19	0.28
235-249	0.35*	0.26	0.24	0.25
257-283	0.31*	0.25	0.23	0.28
295-333	0.32*+**	0.28	0.18	0.22
337-351	0.29*	0.23	0.23	0.28
359-375	0.32*+**	0.27	0.23	0.28
395-415	0.31*	0.23	0.22	0.21

NOTE: * indicates sidewall core

** indicates whole core

TABLE E-3

SATURATION ESTIMATES IN WELL 214M

Depth, ft	S_w core	S_w adjusted core	S_w EPT	S_w R_t	S_w VOLAN
192-220	0.50*	0.66	0.20	0.33	0.70
235-249	0.34*	0.46	0.50	0.40	0.65
257-283	0.63*	0.78	0.42	0.38	0.71
295-333	0.64*+**	0.73	0.19	0.30	0.73
337-351	0.55*	0.69	0.49	0.60	0.80
359-375	0.67	0.79	0.57	0.69	0.63
395-415	0.56	0.75	0.43	0.48	0.70

NOTE: * indicates sidewall core

** indicates whole core

TABLE E-4

SUPRI PILOT -- TEST PATTERN

Summary of SUNTECH IV Slug Treatments
December, 1981 through July, 1982

Treatment Description	Comments
December, 1981:	
Injected 1900 U.S. gal. 15% active SUNTECH IV, plus enough steam to create a 4 wt.% concentration at sandface.	Only minimal pressure increase observed. Anomalous batch of chemical. Isopropyl alcohol added.
March, 1982:	
Injected 2500 U.S. gal. 15% active SUNTECH IV, plus enough steam to create a 4 wt.% concentration at sandface, as follows:	
a) 1380 plus steam	a) Injection pressure increased to 130 from 75 psig.
b) 5 day hiatus in treatment	
c) 1120 gal. plus 36,000 SCF nitrogen plus steam	c) Injection pressure increased to 150 from 80 psig.
July 14 - 29, 1982:	
Injected a total of 21, 588 U.S. gal. SUNTECH IV. Steam injection throughout test at 150 BPD.	Injection pressures increased to 120 from 80 psig during injection of steam plus SUNTECH IV.
a) 100,000 SCF nitrogen injected over 8 hours on July 19.	a) Injection pressure increased to 210 from 120 psig.
b) SUNTECH IV injection continued, after nitrogen injection stopped, at a rate of 1.5 GPM for 86 hours.	b) Injection pressure dropped to 150 psig, decreasing to 120 psig.
c) Injected second nitrogen slug of 200,000 SCF over a 10 hour period on July 28.	c) Injection pressure increased to 210 from 140 psig.
d) SUNTECH IV treatment discontinued on July 29.	d) Injection pressure began gradual decrease over ensuing 5 days to 100 psig. from 140 psig.

TABLE E-5

SUPRI Pilot

McManus Lease, Kern River Field
Evaluation of Steam Distribution by Chemical Tracer

Pattern	Producer	Location Relative to Injector	% of Total Steam Received at Producer	
			Before[1] 1st SUNTECH IV Slug at Test Pattern	After[2] 1st SUNTECH IV Slug at Test Pattern
Test (208)	114	NE	60	68
	120	SE	32	20
	119	SW	7	10
	113B	NW	1	2
Control (214)	126	NE	50	40
	133	SE	15	20
	132	SW	20	20
	125	NW	15	20

1. June, 1982
2. August, 1982

TABLE E-6

ANALYSIS OF INJECTIVITY PROFILE, WATER PHASE, JULY 1982

Date	PERCENTAGE OF FLOW ENTERING				REMARKS
	Slice 3A	Slice 3B	Slice 4	Below Slice 4	
7/12	5	17	75	3	Prior to surfactant injection. Significant water flow into slice 4.
7/15	41	47	12	0	After 1 day continuous surfactant injection at 0.25 gpm. Foam diverting flow into slices 3A and 3B.
7/19	33	54	13	0	Before nitrogen addition. Surfactant flow at 1.25 gpm.
7/19	38	50	12	0	2 hours after terminating nitrogen injection at 12,500 SCFH. 100,000 SCF added.
7/22	51	43	6	0	2.5 days after terminating nitrogen injection.
7/26	44	51	5	0	6.5 days after terminating nitrogen injection.
7/29	42	50	8	0	0.5 day after terminating 2nd nitrogen injection. 200,000 SCF added.
8/2	1	0	99	0	4 days after terminating surfactant slug addition. 21,600 gallons total added. Flow being diverted into slice 4.
8/4	1	4	94	1	7 days after terminating surfactant slug additon.

TABLE E-7

ANALYSIS OF INJECTIVITY PROFILE, GAS PHASE, JULY 1982

DATE	PERCENTAGE OF FLOW ENTERING Slice 3A	Slice 3B	Slice 4	Below Slice 4	REMARKS
7/12	7	11	82	0	Prior to surfactant injection. Appreciable gas flow into slice 4.
7/15	20	22	55	3	After 1 day continuous surfactant injection at 0.25 gpm. Foam diverting steam flow to slices 3A and 3B.
7/19	40	56	4	0	Before nitrogen addition. Surfactant flow at 1.25 gpm.
7/19	54	27	19	0	2 hours after terminating nitrogen injection at 12,500 SCFH. 100,000 SCF added.
7/22	46	39	11	4	2.5 days after terminating nitrogen injection.
7/26	44	51	5	0	6.5 days after terminating nitrogen injection.
7/29	28	36	36	0	0.5 day after terminating 2nd nitrogen injection. 200,000 SCF added. Steam flow to slice 4 increasing.
8/2	13	6	80	1	4 days after terminating surfactant slug addition. 21,600 gallons total added. Appreciable flow to slice 4.
8/4	3	6	87	4	7 days after terminating surfactant slug addition. No significant change in flow to slice 4.

TABLE E-8

SUPRI Pilot

Comparison of Porosity - Saturation Values

Variable Examined	Sources Compared	Correlation Coefficient
Porosity	Adjusted Core with D/N Log	-0.04
	Adjusted Core with VOLAN	0.00
Water Saturation	Adjusted Core with VOLAN	0.17
	Adjusted Core with EPT Log	-0.05
	EPT Log with VOLAN	-0.28
	EPT Log with Resistivity Log	0.81
Porosity x Water Saturation	Adjusted Core with VOLAN	0.01
	Adjusted Core with EPT Log	-0.05
	Adjusted Core with Resistivity Log	-0.05
	EPT Log with VOLAN	-0.09

TABLE E-9

Performance Indices for Low Concentration Test
Pattern 590-21, Midway Sunset Field

A. Injection ratios

	Nov.80-Oct.81
Pounds of chemical/barrel of oil	1.5 #/Bbl
Mcf of air/barrel of oil	0.1 Mcf/Bbl
Barrels of steam/barrel of oil	7 Bbls/Bbl

B. Production performance

	Pre-Pilot Period (1) June 80-Oct.80	Transition Period (2) Nov.80-Jan.81	Oil Production Period (3) Feb.81-Oct.81
Oil Production	18 B/D	16 B/D	71 B/D
Water Production	250 B/D	190 B/D	210 B/D
Water Cut	93%	92%	75%
Steam Injection*	330 B/D	510 B/D	440 B/D
Oil/Steam Ratio	0.05	0.03	0.16

* Approximately 50% quality

(1) Five-month period prior to start of test
(2) Three-month period from start of chemical/gas injection to first significant increase in oil production
(3) Nine-month period from early oil response to peak oil production

TABLE E-10

History of Oil Production by Producing Well
Pattern 590-21, Midway Sunset Field

	Average Daily Oil Rate, BOPD			
Year	Well 194	Well 24	Well 209	Well 23
1971	19	30	22	30
1972	16	27	19	27
1973	19	19	16	16
1974	25	16	22	52
1975	36	22	30	90
1976	25	16	22	38
1977	33	3	11	27
1978	5	14	8	27
1979	11	3	5	11
1980	3	3	3	19
1981	38	14	7	12
1982(1st quarter)	27	10	10	16

TABLE E-11

Individual Well Average Oil Rates
Pattern 590-21, Midway Sunset Field

Well	Location relative to injector	At the end of steam drive (Jun.-Oct./80)	During low concentration test (Feb.-Aug./81)	During replication test (Nov./81-Mar./82)
	A. Rates in barrels per day			
194	N	4	47	27
24	E	2	11	15
209	S	8	4	10
23	W	3	10	20
Pattern Total		17	72	72
	B. Rates expressed as percent of pattern total			
194	N	23.5	65.3	37.5
24	E	11.8	15.3	20.8
209	S	47.1	5.5	18.9
23	W	17.6	13.9	27.8
Pattern Total		100.0	100.0	100.0

TABLE E-12

Summary of Performance during Foam Treatments
San Ardo Pilot

	Month	Daily Rates, BPD Oil	Steam	Oil-Steam Ratio	Water Cut,%	Depletion[1.] Index
#1	10/81	-	-	-	-	-
	11	185	2450	0.076	-	-
	12	188	2670	0.070	-	-
	1/82	161	1620	0.061	97	2.03
	2	235	2690	0.087	-	-
	3	224	2550	0.088	92	1.10
#2	4	212	2400	0.088	-	-
	5	198	2200	0.090	-	-
	6	220	-	-	-	-

Test #1: 69,200 lbs. Thermophoam BW-D plus 4.6 million scf nitrogen.

Test #2: 104,000 lbs. Thermophoam BW-D plus 5.6 million scf nitrogen.

1. Depletion Index = (Oil + Water Produced)/Steam Injected

TABLE E-13

TDS Content of Produced Water
Inner Ring of Producers
San Ardo Pilot

Sample Date	TDS Content, ppm Inner Ring Producer			
	412	413	414	415
09/09/81	7,460	5,060	4,890	15,600
10/01/81	7,320	7,520	4,320	13,800
10/13/81	-	-	-	14,500
10/22/81	-	4,770	4,100	-
11/27/81	4,360	5,550	3,590	14,800
12/05/81	8,590	5,500	3,310	13,800
12/22/81	10,900	7,600	-	12,400
01/19/82	-	7,800	7,100	16,100
05/24/82	3,380	3,260	2,780	4,100
06/07/82	2,400	2,350	975	3,000
06/21/82	2,060	1,910	910	2,500
06/29/82	4,500	4,150	2,340	6,200

TABLE E-14

CORCO Pilot - North Kern Front Field
Chemical Tracer Arrival Times

Pattern	Well	Pre-treatment Tracer Times, hrs. 1st Arrival	Pre-treatment Tracer Times, hrs. Peak	During Treatment Tracer Times 1st Arrival	During Treatment Tracer Times Peak
Witmer B2-3	2-2	3	14	1	25
	3-2	N.A.	N.A.	1	92
	3-3	3	10	1	233
	3-4	3	7	1	9
	2-4	3	9	1	27
	1-4	-	-	1	186
	1-3	45	49	19	44
	1-2	4	9	10	68
Witmer B2-5	2-4	5	10	-	-
	3-4	3	9	-	-
	3-5	1	22	28	28
	3-6	4	5	1	27
	2-6	5	12	16	81
	1-6	21	25	60	168
	1-5	13	21	-	-
	1-4	-	-	5	5
Witmer A2-7	2-6	2	8	2	15
	3-6	1	12	7	44
	3-7	1	9	2	27
	3-8	2	9	-	-
	2-8	3	9	1	16
	1-8	-	-	15	15
	1-7	-	-	51	77
	1-6	-	-	44	60

TABLE E-15

CORCO Pilot - North Kern Front Field
Injection Profiles -Mitchel 63

	Depth Interval, ft.	% of Total Injection into Interval 6/23/80	6/24/80	6/25/80
A. Vapor	1540 - 45	3	-	-
	45 - 50	4	-	-
	50 - 55	4	-	-
	55 - 60	6	6	1
	60 - 65	5	8	8
	65 - 70	5	3	3
	70 - 75	2	7	6
	75 - 80	2	3	3
	80 - 85	3	9	28
	85 - 90	34	33	44
	90 - 95	32	31	7
		100	100	100
B. Liquid	1540 - 45	-	-	-
	45 - 50	-	-	-
	50 - 55	-	-	-
	55 - 60	-	-	-
	60 - 65	-	-	-
	65 - 70	-	-	-
	70 - 75	-	-	-
	75 - 80	-	-	-
	80 - 85	37	36	41
	85 - 90	37	38	41
	90 - 95	26	26	18
		100	100	100

TABLE E-16

Average Oil-Steam Ratios
Before and After Foam Treatment
CORCO/Petro-Lewis Pilot Patterns
North Kern Front Field

	Before COR-180 Treatments		After COR-180 Treatments
	January 1979-March 1980	July 1979-March 1980	March 1980-March 1981
Witmer B2-3	0.205	0.253	0.361
Witmer A2-7	0.2475	0.295	0.2475
(Witmer B2-3) minus (Witmer A2-7)	-0.0425	-0.042	+0.1135

TABLE E-17

CORCO Pilot - North Kern Front Field
Average Quarterly Oil-Steam Ratios

Year	Quarter	Pattern					
		Mitchel			Witmer		
		63	65	67[3]	B2-3	B2-5	A2-7[3]
1979	1	0.14	0.13	0.18	0.13	0.34	0.16
	2	0.08	0.06	0.11	0.14	0.08	0.09
	3	0.10	0.08	0.11	0.22	0.06	0.16
	4	0.17	0.13	0.16	0.33	0.16	0.26
1980	1	0.12[1]	0.10[2]	0.14	0.21[4]	0.05	0.23
	2	0.14	0.08	0.16	0.34	0.07[5]	0.19
	3	0.16	0.08	0.14	0.32	0.10	0.26
	4	0.16	0.08	0.21	0.34	0.13	0.15
1981	1	0.05	0.04	0.10	0.44	0.32	0.22
	2	0.13	0.16	0.36	0.22	0.23	0.24
	3	0.08	0.10	0.16	0.32	0.22	0.22
	4	0.06	0.06	0.14	0.29	0.09	0.32
1982	1	0.05	0.06	0.19	0.21	0.12	0.11
	2	0.08	0.09	0.11	0.38	0.28	0.11
	3	0.06	0.12	0.15	0.32	0.21	0.16

1. Begin COR-GEL treatments 3/11/80
2. Begin COR-180 treatments 1/21/80
3. Control pattern
4. Begin COR-180 treatments 3/11/80
5. Begin COR-GEL treatments 5/11/80

TABLE E-18

CORCO Pilot - North Kern Front Field
Comparison of Average Oil-Steam Ratios
Before and After Treatments

Pattern	Type of Treatment	Average Oil-Steam Ratio		Percent Change
		Before Treatment	After Treatment	
Witmer B2-3	COR-180	0.206	0.318	+54
Witmer B2-5	COR-GEL	0.132	0.183	+39
Witmer A2-7	NONE	0.180	0.198	+10
Mitchel 63	COR-GEL	0.122	0.097	-20
Mitchel 65	COR-180	0.100	0.088	-12
Mitchel 67	NONE	0.140	0.172	+23

TABLE E-19

Observed Injection Profiles in the Vapor and Liquid Phases
SUPRI Pilot - Pattern 208

Phase	Treatment Particulars	Percent of Total Injection Entering Layer			
		3A	3B	4	Total
Vapor	Prior to foam treatment	7	11	82	100
	After foam treatment	46	44	10	100
Liquid	Prior to foam treatment	5	17	78	100
	After foam treatment	42	49	9	100

TABLE E-20

Comparison of Observed and Calculated Vapor Phase Injection Profiles
SUPRI Pilot - Pattern 208

Source	Treatment Particulars	Percent of Total Injections Entering Layer 3A	3B	4	Total
A. SUPRI performance data	1. Prior to foam treatment	7	11	82	100
	2. After injecting approximately 4000 RES. BBL. of foam	46	44	10	100
B. Model calculation	1. Prior to foam treatment	7	11	82	100
	2. 4000 BBL. of 1 cp. foam	7.4	11.5	81.1	100
	3. 4000 BBL. of 50 cp. foam	8.8	13.4	77.8	100
	4. 40,000 BBL. of 50 cp. foam	8.4	12.9	78.7	100
	5. 40,000 BBL. of 1000 cp. foam	8.5	13.0	78.5	100

TABLE E-21

SUPRI Pilot - Pattern 208
History Match of Observed Changes in Injection Profile
in Response to Foam Injection

A. Injection profile match (vapor phase)

Layer	Historical 3A	3B	4	Model 3A	3B	4
% entering layer before treatment	7	11	82	7	11	82
% entering layer after treatment	46	44	10	46	44	10

B. Effective foam viscosities required to attain match

Layer	Permeability (relative units)	Effective Foam Viscosity, cp
3A	195	44
3B	785	70
4	1822	1850

FIGURES

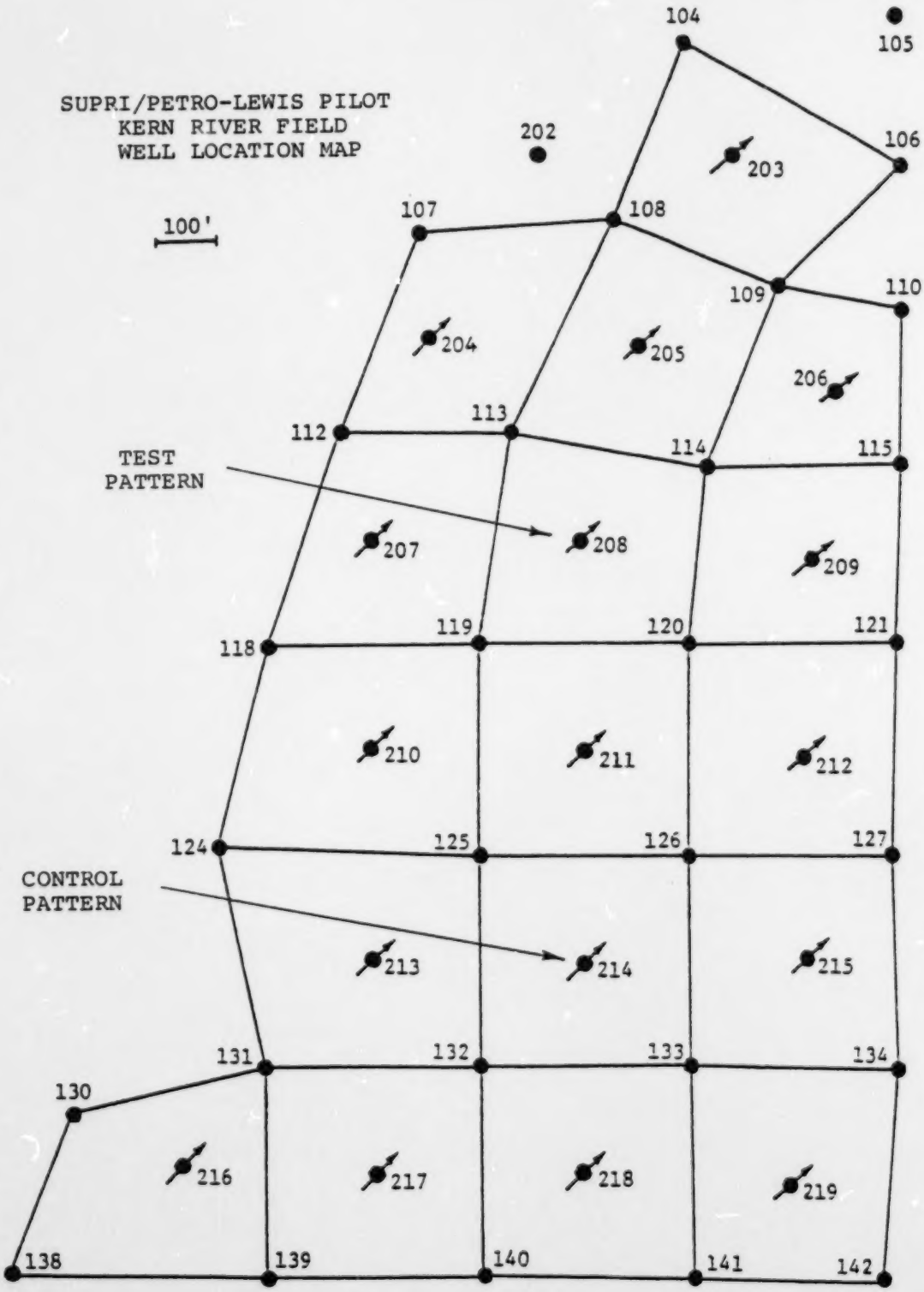

SUPRI/PETRO-LEWIS PILOT
KERN RIVER FIELD
WELL LOCATION MAP
100'
104
105
202
106
203
107
108
109
110
204
205
206
112
113
114
115
TEST
PATTERN
207
208
209
118
119
120
121
210
211
212
124
125
126
127
CONTROL
PATTERN
213
214
215
131
132
133
134
130
216
217
218
219
138
139
140
141
142

FIGURE E-1

SUPRI/PETRO-LEWIS PILOT
KERN RIVER FIELD
LOG CROSS-SECTION IN TEST PATTERN
CORRELATION BETWEEN WELLS 208 AND 113B

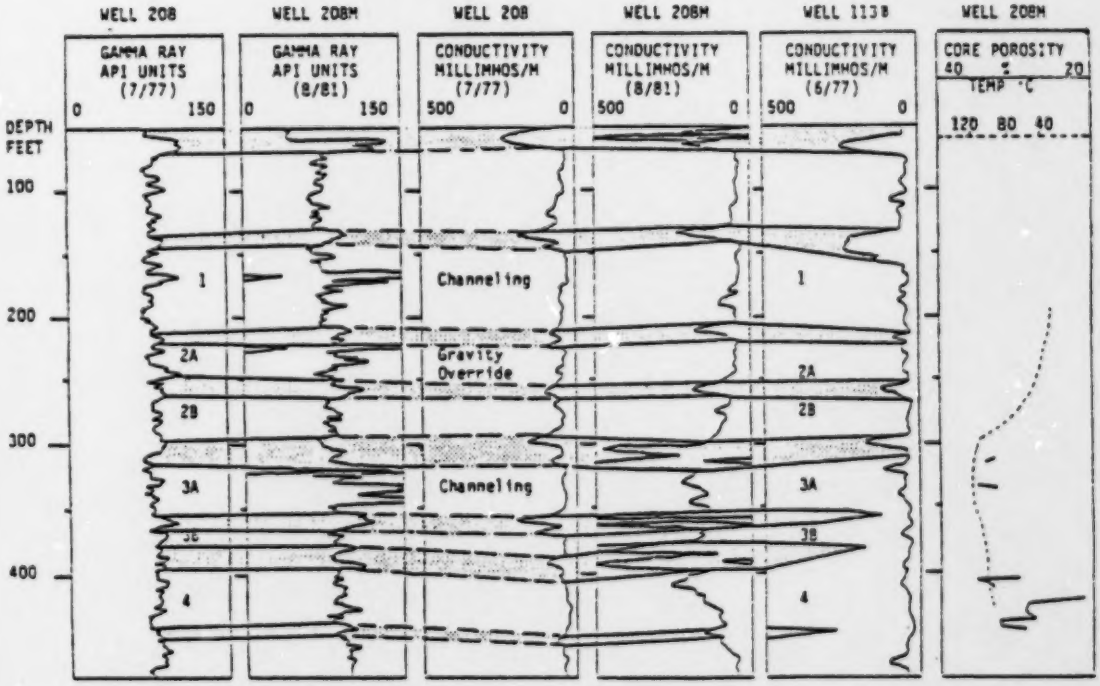


FIGURE E-2

SUPRI/PETRO-LEWIS PILOT
KERN RIVER FIELD
LOG CROSS-SECTION IN CONTROL PATTERN
CORRELATION BETWEEN WELLS 214 AND 125

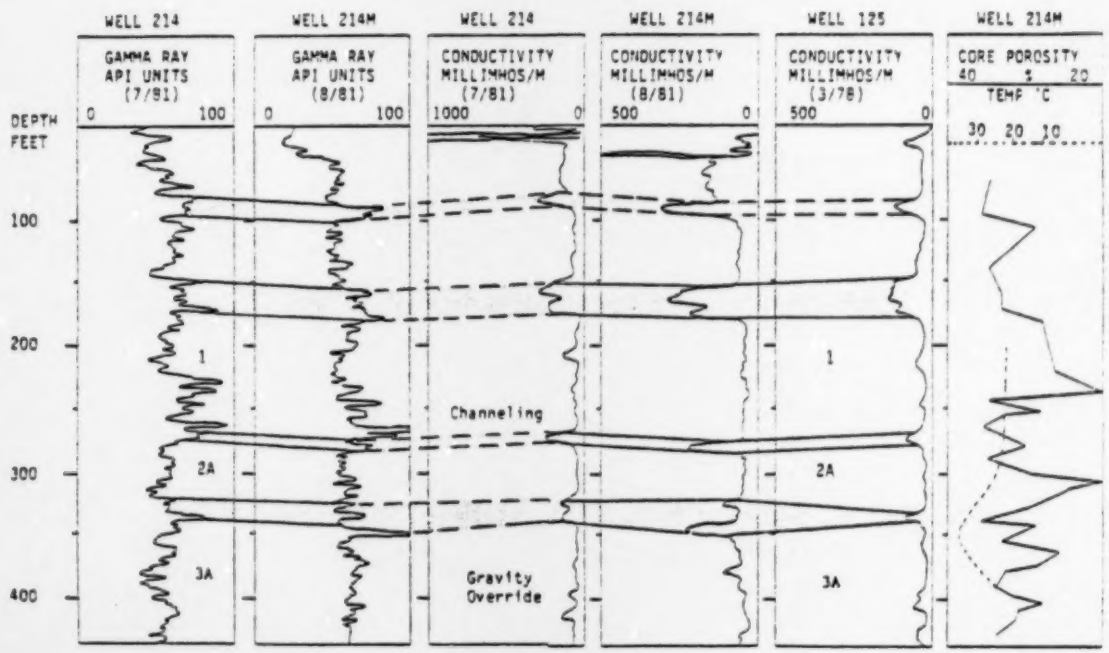


FIGURE E-3

SUPRI/PETRO-LEWIS PILOT
KERN RIVER FIELD
PRODUCTION PERFORMANCE BEFORE, DURING AND AFTER
JULY 1982 SUNTECH IV TREATMENT
AT TEST PATTERN

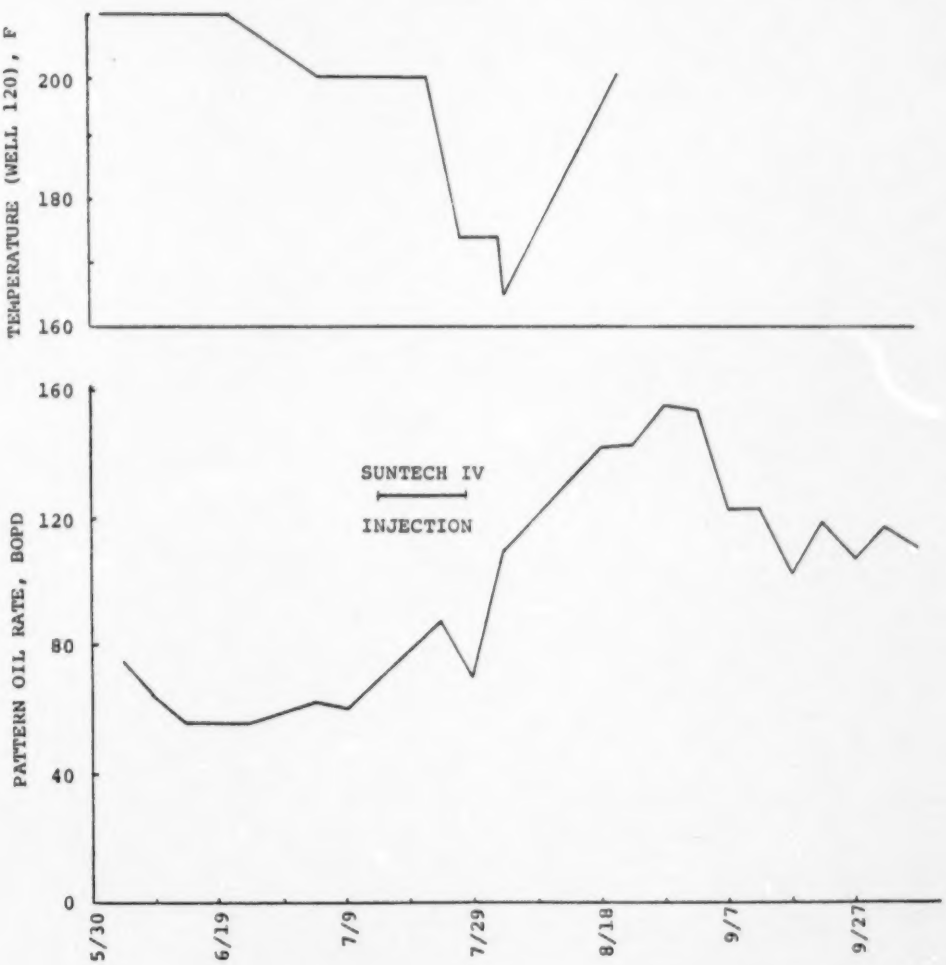
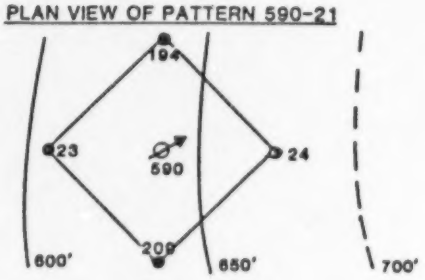


FIGURE E-4


PLAN VIEW OF PATTERN 590-21
194
23
590
24
209
600'
650'
700'

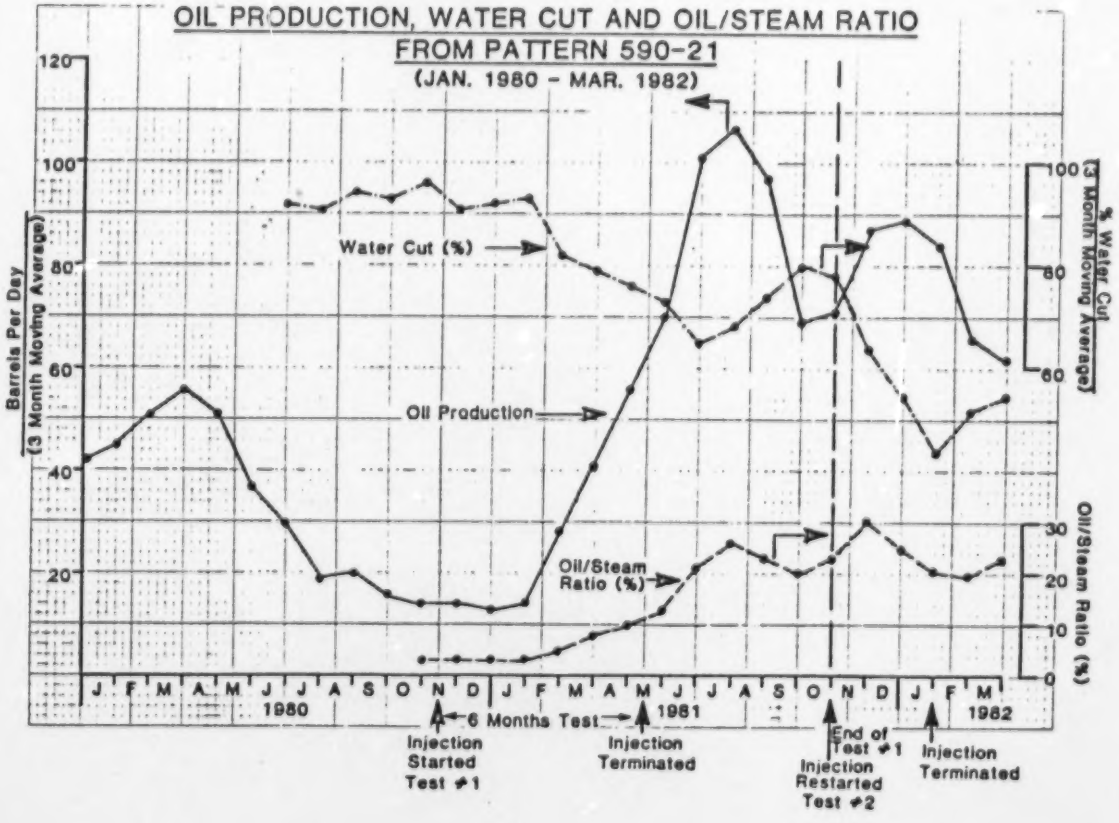

OIL PRODUCTION, WATER CUT AND OIL/STEAM RATIO
FROM PATTERN 590-21
(JAN. 1980 - MAR. 1982)
Barrels Per Day
(3 Month Moving Average)
% Water Cut
(3 Month Moving Average)
Oil/Steam Ratio (%)
Water Cut (%)
Oil Production
Oil/Steam Ratio (%)
120
100
80
60
40
20
0
J F M A M J J A S O N D J F M A M J J A S O N D J F M
1980
1981
1982
6 Months Test
Injection Started Test #1
Injection Terminated
End of Test #1
Injection Restarted Test #2
Injection Terminated

FIGURE E-5

MIDWAY SUNSET PILOT
CLD EXPERIMENTAL PROGRAM
TEMPERATURE SURVEYS BEFORE & AFTER
FOAM TREATMENTS

	DATE
WELL NO.: 23-21N	10-19-79
CASING @ 624	9-30-80
LINER: 607-1100	3-19-81
PERFS: 613-1100	8-10-81
PUMP SHOE DEPTH: 1049 KB	1- 7-82
BBLS. INJECTED: 5721	
GENERATOR NO.: 41	
ZERO POINT: K.B +10	
CYCLE NO.: 6	

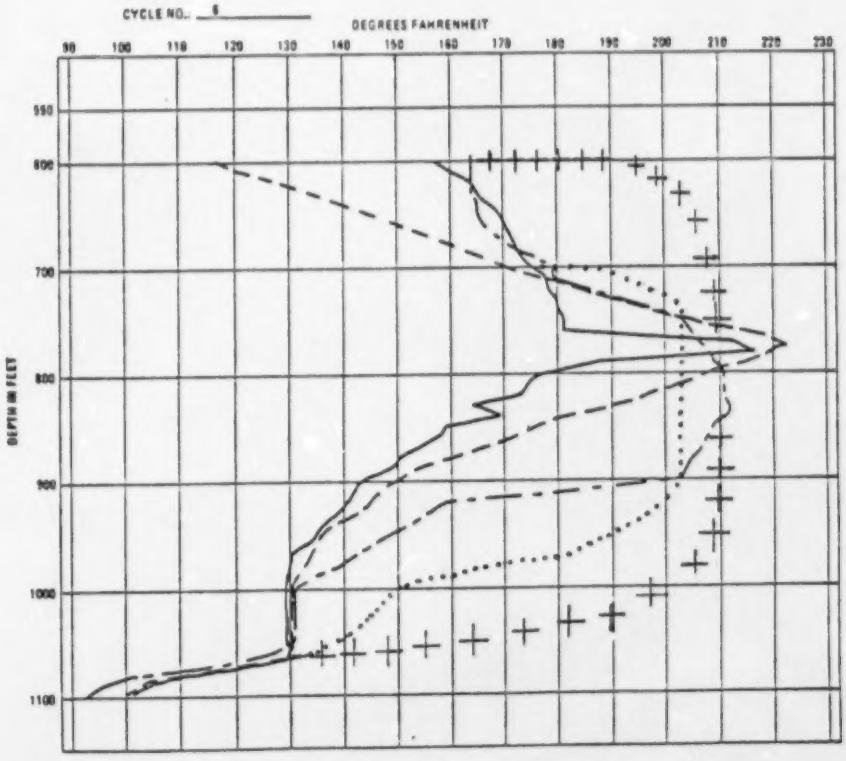
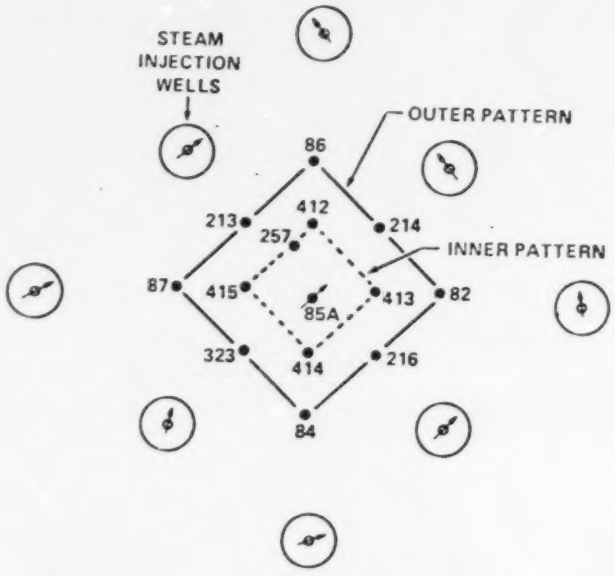
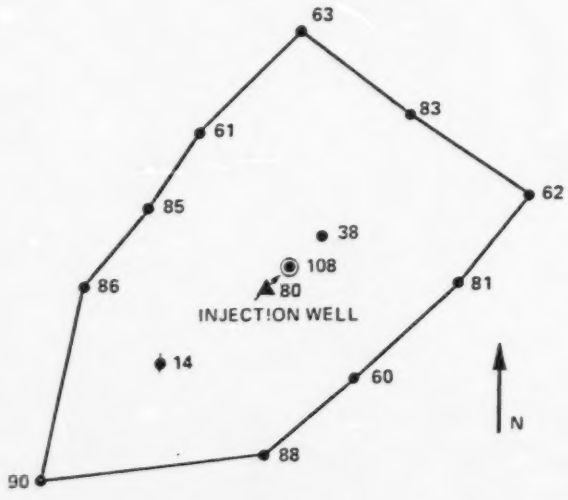


FIGURE E-6



San Ardo pattern and surrounding wells



LEGEND

INJECTION WELL

PRIMARY WELL TO BE INFLUENCED BY PROJECT

0 200 400 600

FEET

Test pattern for Conoco field test

FIGURE E-7

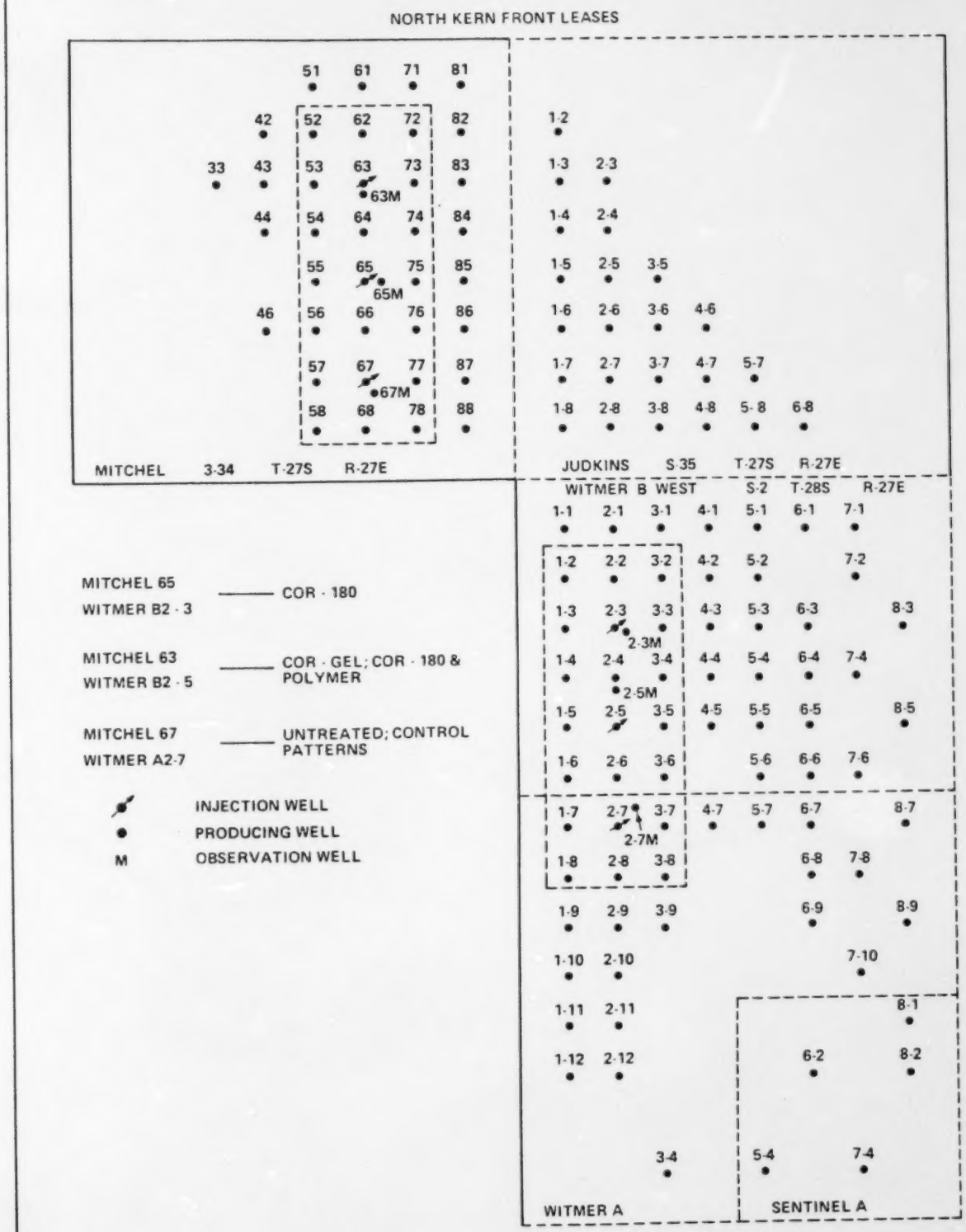

NORTH KERN FRONT LEASES
MITCHEL 3-34 T-27S R-27E
JUDKINS S-35 T-27S R-27E
WITMER B WEST S-2 T-28S R-27E
WITMER A
SENTINEL A
63M
65M
67M
2-3M
2-5M
2-7M
MITCHEL 65
WITMER B2 - 3
COR - 180
MITCHEL 63
WITMER B2 - 5
COR - GEL; COR - 180 & POLYMER
MITCHEL 67
WITMER A2-7
UNTREATED; CONTROL PATTERNS
INJECTION WELL
PRODUCING WELL
M OBSERVATION WELL

FIGURE E-8